**BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA**

Application of Pacific Gas and Electric Company to Recover in Customer Rates the Costs to Support Extended Operation of Diablo Canyon Power Plant from September 1, 2023 through December 31, 2025 and for Approval of Planned Expenditure of 2025 Volumetric Performance Fees (U 39 E)	Application 24-03-018

REPLY OF PACIFIC GAS AND ELECTRIC COMPANY (U 39 E) TO PROTESTS

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Date: May 20, 2024

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I. INTRODUCTION

Pursuant to Rule 2.6(e) of the California Public Utilities Commission ("Commission") Rules of Practice and Procedure, Pacific Gas and Electric Company ("PG&E") files its reply to protests and responses to its March 29, 2024, *Application of Pacific Gas and Electric Company to Recover in Rates the Costs to Support Extended Operation of Diablo Canyon Power Plant from September 1, 2023 through December 31, 2025 and Approval of Planned Expenditures of 2025 Volumetric Performance Fees*, amended on April 8, 2024 ("Application").

The following parties submitted protests: Alliance for Nuclear Responsibility ("A4NR"),[1] California Community Choice Association ("CalCCA"),[2] CAlifornians for Renewable Energy, Inc. ("CARE"),[3] Direct Access Customer Coalition/Alliance for Retail Energy Markets

[1] Alliance for Nuclear Responsibility's Protest ("A4NR Protest"), May 8, 2024.
[2] California Community Choice Association's Protest to the Application of Pacific Gas and Electric Company ("CalCCA Protest"), May 8, 2024.
[3] CAlifornians for Renewable Energy, Inc. (CARE) Protest to Application as Amended April 8, 2024, ("CARE Protest"), May 7, 2024.

("DACC/AReM"),[4] Public Advocates Office at the Commission ("Cal Advocates"),[5] Southern California Edison Company ("SCE"),[6] The Utility Reform Network ("TURN").[7] The following parties submitted responses: Coalition of California Utility Employees ("CUE"),[8] Green Power Institute ("GPI"),[9] San Diego Gas & Electric Company ("SDG&E"),[10] and Small Business Utility Advocates ("SBUA").[11]

PG&E appreciates the interest and engagement of these stakeholders and looks forward to working with parties during the course of this proceeding. Since the passage of Senate Bill ("SB") 846, significant efforts and implementation tasks have been undertaken by the Commission, other state agencies, PG&E, and stakeholders to effectuate the extension of Diablo Canyon Power Plant ("DCPP"), which commences on November 3, 2024 for Unit 1 and August 27, 2025 for Unit 2. PG&E is honored to respond to the State's call for action to extend operations at DCPP to promote grid reliability and help meet the state's greenhouse-gas ("GHG")-emissions reduction targets. In addition, PG&E wishes to emphasize the importance of a final decision by the Commission in this matter by December 2024. As PG&E explained in its

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[4] Response of the Direct Access Customer Coalition and the Alliance for Retail Energy Markets to the Application of Pacific Gas and Electric Company (U 39 E) to Recover in Customer Rates the Costs to Support Extended Operation of Diablo Canyon Power Plan from September 1, 2023 through December 31, 2025 and for Approval of Planned Expenditures of 2025 Volumetric Performance Fees ("DACC/AReM Response"), May 8, 2024.
[5] Protest of the Public Advocates Office ("Cal Advocates Protest"), May 8, 2024.
[6] Southern California Edison Company's (U 338-E) Protest of Application Pacific Gas and Electric Company (U 39 E) to Recover in Customer Rates the Costs to Support Extended Operation of Diablo Canyon Power Plant from September 1, 2023 Through December 31, 2025 And For Approval of Planned Expenditure of 2025 Volumetric Performance Fees ("SCE Protest"), May 8, 2024.
[7] Protest of The Utility Reform Network ("TURN Protest"), May 8, 2024.
[8] Response of the Coalition of California Utility Employees to Application of Pacific Gas and Electric Company ("CUE Response"), May 8, 2024.
[9] Response of the Green Power Institute to the Application of PG&E ("GPI Response"), May 8, 2024.
[10] San Diego Gas & Electric Company (U 902 E) Response to Application to Pacific Gas and Electric Company to Recover in Customer Rates the Costs to Support Extended Operation of Diablo Canyon Power Plant from September 1, 2023 through December 31, 2025 and for Approval of Planned Expenditure of 2025 Volumetric Performance Fees ("SDG&E Response"), May 8, 2024.
[11] Small Business Utility Advocates' Response to Application of Pacific Gas and Electric Company to Recover in Customer Rates the Costs to Support Extended Operation of Diablo Canyon Power Plant from September 1, 2023 through December 31, 2025 and for Approval of Planned Expenditures of 2025 Volumetric Performance Fees ("SBUA Response"), May 8, 2024.

Application, a decision by the end of the year is necessary in order for the investor-owned utilities ("IOU") to develop their respective adjusted electric rates to be implemented on January 1, 2025.

In addition to this reply, PG&E attaches the final California Energy Commission ("CEC") *Staff Report-Senate Bill 846 Diablo Canyon Power Plant Extension Cost Comparison* to satisfy Commission directives from D.23-12-036[12] as Attachment A.

II. PG&E'S REPLY TO PROTESTS

A. Issues in Scope of the Proceeding

PG&E reaffirms that the issues it identifies in its Application on page 24 should be found in scope. While PG&E does not respond substantively to parties' arguments below, PG&E agrees that the following issues identified in protests and responses are in scope of the proceeding:

- Reasonableness of extended operations costs covering the period of September 1, 2023, to December 31, 2025 (the "Record Period") and Public Utilities Code Section 451 evaluations.[13]
- Federal and state income tax gross up of fixed management fees.[14]
- Fuel costs during the Record Period.[15]
- Compliance of PG&E's plan for volumetric performance fees ("VPF") collected for the period of November 3, 2024, to December 31, 2025 with D.23-12-036 and Section 712.8(s)(1).[16]

[12] D.23-12-036, p. 61. The Commission directed PG&E to include a copy of the CEC's final Cost Comparison Report in its application, but it had not been issued at the time of the application. Following the submission of PG&E's application, the CEC issued the final report on May 3, 2024; thus, PG&E attaches it to this reply.
[13] A4NR Protest, pp. 1-4; TURN Protest, p. 4; CARE Protest, pp. 2-5; GPI Protest, p. 2.
[14] TURN Protest, p. 3.
[15] A4NR Protest, pp. 5-6.
[16] A4NR Protest, pp. 6-7; TURN Protest, p. 4; CalCCA Protest, pp. 14-15.

- Whether the allocation of specific costs to customers in SDG&E's service area is reasonable and consistent with the parameters established in SB 846 and D.23-12-036.[17]
- Substitution capacity forecast costs.[18]

In addition, PG&E agrees with the wording of issues identified in scope by Cal Advocates.[19] PG&E also agrees that it bears the burden of proof to demonstrate the reasonableness of the costs proposed for recovery from customers, whether bundled service or departed load.[20]

Finally, while PG&E agrees that costs will be in scope of the proceeding, it responds to TURN's and A4NR's incorrect quantification of updates to the DCPP extended operations period costs since Rulemaking (R.) 23-01-007. When comparing PG&E's present total forecast for the period of 2024 to 2030 to the same costs presented in R.23-01-007, PG&E's present operations and maintenance ("O&M") forecast is four percent lower and the fully loaded revenue requirement forecast including statutory fees and illustrative revenue requirement overheads, subject to update in the 2027 GRC, has increased by 11 percent. 8%. PG&E discusses this in more detail in Section B below.

B. A4NR's Allegation of a Rule 1.1 Violation is Unfounded and Should Be Rejected

A4NR argues that PG&E's cost forecast and presentation in R.23-01-007 submitted in May 2023 and July 2023 compared to the presentation in this proceeding gives rise to gross negligence or recklessness, if not willful misrepresentation; and recommends that the Commission issue an Order to Show Cause why PG&E should not be found in violation of Rule 1.1.[21] A4NR grossly misrepresents the costs of extended operations in PG&E's Chapter 2 Attachment A and its recommendation should be rejected.

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[17] SDG&E Response, p. 5. PG&E agrees with SDG&E that this issue is incorporated in PG&E's proposed issue of: "Whether the calculation of the non-bypassable charge and rate proposals by PG&E, SCE, and SDG&E comply with D.23-12-036" in its Application.
[18] CalCCA Protest, pp. 13-14.
[19] Cal Advocates Protest, p. 4.
[20] CalCCA Protests, p. 4.
[21] A4NR Protest, pp. 4-5.

A4NR incorrectly asserts that PG&E's DCPP extended operations forecast has grown from $5.2 billion to $8.1 billion in the R.23-01-007 forecast, to $11.8 billion in this Application.[22] In presenting these figures, A4NR incorrectly includes original operations period costs funded through the 2020 and 2023 General Rate Cases for the period 2022-2026,2025, costs that have nothing to do with extended operations and the scope of this proceeding. To the contrary, for the years of extended operations (2024 through 2030) the O&M forecast in this proceeding is 4 percent lower than the forecast for the same period in R.23-01-007.[23] When including all statutory fees and illustrative revenue requirement overheads subject to update in the 2027 GRC, the forecast increases by 11 percent.[24] This change is primarily the result of the inclusion of the illustrative Administrative and General ("A&G") overhead from 2027 through 2030, which is subject to update in PG&E's upcoming 2027 GRC filing, inclusion of resource adequacy substitution costs, and more current tax and financing forecasts.

Rule 1.1 says, in part, that "Any person" who transacts with the Commission "agrees to…never to mislead the Commission or its staff by an artifice or false statement of fact or law." A4NR is unable to substantiate or present any evidence that PG&E's cost presentation from R.23-01-007 violated Rule 1.1, because no violation occurred. First, PG&E provided its most recent and complete set of cost information in R.23-01-007 pursuant to its scoping ruling. First, PG&E provided its most recent and complete set of cost information in R.23-01-007 pursuant to the scoping ruling.[25] PG&E repeatedly informed the Commission and parties in its May 2023

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[22] Id., p. 4, p. 8.
[23] In calculating the variance in the O&M forecast and the fully loaded revenue requirement between the cost presentation in R.23-01-007 and this Application, PG&E compared the Table 1-3 (lines 2, 3, 4, and 5) and Table 1-4 (lines 1 and 3) from its rebuttal testimony submitted in R.23-01-007 to Attachment A in Chapter 2 of PG&E's Prepared Testimony (lines 60-63, 66-67, 72, 74, 75, 77, 78, 80-81, and 83).
[24] Id.
[25] *Assigned Commissioner's Scoping Memo and Ruling* issued in R.23-01-007 ("R.23-01-007 Scoping Ruling"), April 6, 2023, p. 13.

testimony,[26] July 2023 rebuttal testimony,[27] opening brief,[28] and reply brief,[29] that the costs presented in its May 2023 and July 2023 testimony were its best available cost information for extended operations from 2023 to 2030 at that point in time. Prior to the passage of SB 846, PG&E was preparing to retire DCPP, and only following the passage of SB 846, began to prepare for the possibility of extended operations.

At the time of the submission of its testimony in R.23-01-007, PG&E's most recent and complete set of cost information for extended operations were from its Department of Energy Civil Nuclear Credit Application, which were submitted using the Electric Utility Cost Group ("EUCG") methodology.[30] In particular, PG&E focused on presenting costs as directed in the scope of R.23-01-007.[31] The costs identified in the scoping ruling were: 1) costs associated with likely or potential improvements that might reasonably be required as part of the Nuclear Regulatory Commission ("NRC") relicensing process, 2) needed maintenance and/or capital expenditures to operate to 2030, 3) projects through 2030, and 4) seismic safety.[32] The costs identified in the scoping ruling were: (1) costs associated with likely or potential improvements that might reasonably be required as part of the Nuclear Regulatory Commission ("NRC") relicensing process, (2) needed maintenance and/or capital expenditures to operate to 2030, (3) projects through 2030, and (4) seismic safety.[33] Also, in its May 2023 testimony, PG&E specifically noted that its presentation did not include all costs and identified the types of costs not included in its presentation of costs using the EUCG methodology in order to assist the Commission and parties used to reviewing costs in the Major Work Categories ("MWC") format.[34]

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[26] PG&E Prepared Testimony submitted in R.23-01-007 ("PG&E Prepared Testimony in R.23-01-007"), May 19, 2023, pp. 3-15.
[27] PG&E Rebuttal Testimony submitted in R.23-01-007, July 28, 2023, p. 1-4, lines 11-16.
[28] PG&E Opening Brief submitted in R.23-01-007,
[29] PG&E Reply Brief submitted in R.23-01-007, pp. 5-6.
[30] PG&E Prepared Testimony submitted in R.23-01-007, May 19, 2023, pp. 2-6.
[31] R.23-01-007 Scoping Ruling, April 6, 2023, p. 13.
[32] Id.
[33] Id.
[34] PG&E Prepared Testimony in R.23-01-007, pp. 3-6.

For the purpose of this Application and proceeding, PG&E spent months developing the comprehensive, detailed, and "bottoms up" forecast that is presented in its Application and accompanying testimony. Additionally, PG&E developed a custom-built Results of Operations ("RO") model to incorporate requirements from SB 846 and D.23-12-036. During Phase 1 of R.23-01-007, PG&E did not have the time, resources, or full knowledge of costs for extended operations to develop a specific RO model for DCPP's extended operations. Nor was the purpose of R.23-01-007 to recover costs from customers.

C. Compliance with D.23-12-036 Requirements for Cost Presentation

TURN asserts that PG&E does not comply with the Commission's direction to provide: historical and forecast costs from 2022 to 2030; all DCPP costs to be recovered from ratepayers over time, including General Rate Case ("GRC") categories; and government-funded transition costs.[35] TURN is incorrect. PG&E identified the Commission requirements from D.23-12-036 and their location in its prepared testimony in Table 2-1, titled "D.23-12-036 Compliance Requirements."[36] Specifically, PG&E presents information in compliance with all three of the above-referenced requirements in Chapter 2, Attachment A, titled "Recorded and Forecast Costs: 2022-2030."[37] GRC costs are identified in the column "Funding Category" as "GRC Expense." Government funding is identified in the column "Funding Category" as "DCTRMA" indicating the Diablo Canyon Transition and Relicensing Memorandum Account.

CARE asserts that PG&E did not include 2023 GRC costs, such as A&G and capital expenditures. As referenced above, GRC costs are identified in Chapter 2, Attachment A of PG&E's testimony. CARE is correct that capital costs from the 2020 and 2023 GRC for the years 2022 to 2025 are not included in Attachment A, which PG&E intends to correct in a forthcoming errata testimony submission. In addition, PG&E does not propose to earn a rate of

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[35] TURN Protest, pp. 1-2.

[36] PG&E Prepared Testimony, March 29, 2024, Chapter 2, pp. 2-1 – 2-3.

[37] Some of the information in Attachment A is confidential and available to parties that sign a non-disclosure agreement.

return on (i.e., capitalize) any of the costs presented in this Application.[38] PG&E treated project costs that would typically be capitalized as expense.[39]

Next, TURN asserts that PG&E includes debt financing costs, including working cash in its cost recovery request.[40] TURN also cites to a "Debt Financing Cost" recovery item to compensate for necessary adjustments pertaining to Internal Revenue Code ("IRC") Normalization rules and working cash. PG&E believes that these adjustments to the RO model are necessary to mitigate significant IRC normalization violation concerns and to make PG&E whole for 2024 and 2025 working cash related to DCPP, given that DCPP was assumed to be retired by August 2025 for both units in the 2023 GRC. While in the GRC working cash is traditionally a rate-base item, PG&E's working cash proposal in this case is an expense-only proposal. Further, CARE asserts that PG&E did not include 2023 GRC costs, such as A&G and capital expenditures. As referenced above, GRC costs are identified in Chapter 2, Attachment A of PG&E's testimony. CARE is correct that capital costs from the 2020 and 2023 GRC for the years 2022 to 2025 are not included in Attachment A, which PG&E intends to correct in a forthcoming errata testimony submission. Finally, PG&E does not propose to earn a rate of return on (i.e., capitalize) any of the costs presented in this Application.[41] PG&E treated project costs that would typically be capitalized as expense.[42]

D. A4NR's Argument that Fuel Can Only Be Recovered from Government Funding Is in Error

A4NR argues that incremental fuel costs for extended operations cannot be recovered in customer rates.[43] A4NR's argument is contrary to SB 846 and Commission determinations addressing this issue, which A4NR has previously raised. SB 846 adopts a broadly prescriptive cost recovery and approval process for transition and extended operations costs. Section

[38] Pub. Util. Code § 712.8(h)(1).
[39] PG&E's Prepared Testimony, p. 6-2, lines 10-12.
[40] TURN Protest, p. 4.
[41] Pub. Util. Code § 712.8(h)(1).
[42] PG&E's Prepared Testimony, p. 6-2, lines 10-12.
[43] A4NR Protest, pp. 5-6.

712.8(c)(1)(C) prohibits the recovery of the costs of actions taken "in preparation for extended operations" or actions taken for the license renewal process for the NRC from ratepayers. No similar prohibition on recovery of fuel costs exists in SB 846. Interpreting SB 846 the way A4NR does is contrary to the intent of the Legislature of DCPP's extended operations for State reliability and recovery of the costs of extended operations from the customers receiving the benefits. While Public Resources Code Section 25548.3(c)(3) specifically allows fuel costs to be recovered from the California Department of Water Resources ("DWR") loan, it does not limit fuel costs to *only* being recovered by the DWR loan.

Additionally, the Commission conclusively authorized fuel cost recovery in Resolution ("Res.") E-5299.[44] In Res. E-5299, the Commission found that, ". . . there is no indication in this statutory language, nor elsewhere in SB 846, that the legislature intended to categorically deny recovery of incremental fuel costs in the DCEOBA or limit its recovery to the DCTRMA."[45] In D.23-12-036, the Commission concluded "that the intent of the Legislature was to assign broad responsibility for the costs of extended operations of DCPP to ratepayers of all LSEs subject to the Commission's jurisdiction. . ..."[46] Further, the Commission explains that there is flexibility in certain cost categories that are recovered for extended operations.[47]

E. PG&E's Proposal on RA Capacity and GHG-Free Energy Allocation is Appropriately in Scope

CalCCA,[48] DACC/AReM,[49] SCE,[50] SDG&E[51] oppose inclusion of PG&E's proposal for RA capacity and GHG-free energy allocation to consider the higher cost burden to customers within PG&E's service territory, including to both bundled service and departed load customers. In summary, these parties argue that the issue was already litigated in R.23-01-007, resulting in

[44] Resolution E-5299 ("Res. E-5299"), May 9, 2024.
[45] Id., p. 10.
[46] D.23-12-036, p. 66
[47] Res. E-5299, pp. 10-11.
[48] CalCCA Protest, pp. 7-13.
[49] DACC/AReM Response, p. 3.
[50] SCE Protest, pp. 3-7.
[51] SDG&E Response, pp. 5-11.

D.23-12-036, and assert collateral estoppel arguments. PG&E disagrees. Phase 1 of R.23-01-007 did not contain, as part of its scope, a full consideration of PG&E service territory customers' higher cost burden, nor did D.23-12-036 explicitly address the application of the full statutory language contained in Section 712.8(q), which states that "[t]o the extent the commission decides to allocate any benefits or attributes from extended operations of the Diablo Canyon powerplant, the commission may consider the higher cost to customers in the operator's service area."

During Phase 1 of R.23-01-007, PG&E explained that its interpretation of SB 846 was that an allocation of RA capacity was in conflict with the Legislature's intent of preserving the option of DCPP's extended operations for reliability reasons. In addition, it would assign PG&E with portfolio manager responsibilities on behalf of all LSEs, resulting in additional costs and risks. However, in ordering an allocation of attributes, the Commission did not fully consider the language contained in Section 712.8(q), which expressly allows the Commission to consider the higher cost to customers in the operator's service area in D.23-12-036.[52] Neither CalCCA, DACC/AReM, SCE, or SDG&E have cited to a Finding of Fact, Conclusion of Law, and/or Ordering Paragraph ("OP") in D.23-12-036 within their Application protests or responses that demonstrates Commission consideration of "the higher cost to customers in the operator's service area" when the Commission decided to allocate the RA capacity and GHG-free energy attributes. Neither CalCCA, DACC/AReM, SCE, or SDG&E have cited to a Finding of Fact, Conclusion of Law, and/or Ordering Paragraph ("OP") in D.23-12-036 within their Application protests or responses that demonstrates Commission consideration of "the higher cost to customers in the operator's service area" when the Commission decided to allocate the RA capacity and GHG-free energy attributes.

In any event, PG&E does not seek to "undo attribute allocation methodologies"[53] established by the Commission in D.23-12-036. PG&E is not re-litigating, nor does it disagree

[52] D.23-12-036 considers Section 712.8(q) in authorizing the allocation of RA benefits, not in considering the higher cost to customers in the operator's service territory.
[53] CalCCA Protest, p. 12.

with, the Commission's 12-CP allocation methodology. Rather, PG&E presents a proposal that uses the 12-CP allocation methodology as a basis with an adjustment to account for the higher cost burden to customers within PG&E's service territory, including to both bundled service and departed load customers. As described by GPI, PG&E service territory customers should receive additional consideration in the allocation of RA capacity and environmental attributes given that PG&E service territory customers will be assessed a greater share of the costs of DCPP's extended operations.[54] PG&E agrees as this approach is best aligned with cost causation principles.

While CalCCA and SCE assert that PG&E's customers receive the benefits of the VPF expenditures and any surplus funds from the liquidated damages subaccount,[55] these considerations are not comparable or relevant and there is no statutory language in which these "benefits" are contingent upon one another. The VPFs are "in lieu of a rate-based return on investment"[56] and intended to be in furtherance of public purpose priorities, not the higher cost burden borne by customers in PG&E's service territory. Moreover, the liquidated damages subaccount may not have funds at the end of the extended operations period. Accordingly, PG&E's proposal to account for the higher cost burden to customers within PG&E's service territory, including to both bundled service and departed load customers, is appropriately in scope.

F. TURN's Proposal to Review Performance-Based Disbursement Expenditures and DWR Funds are Out of Scope

TURN argues that PG&E should present testimony addressing how PG&E has recorded and spent the Performance-Based Disbursements ("PBD") funded by the DWR loan for the purpose of ensuring no double recovery occurs.[57] TURN's proposal is squarely outside the scope of this proceeding. In D.23-12-036, the Commission directed that PG&E include government

[54] GPI Protest, pp. 2-3.
[55] CalCCA Protest, p. 8; SCE Protest, pp. 6-7.
[56] Pub. Util. Code § 712.8(f)(5).
[57] TURN Protest, pp. 2-3.

funding streams in its forecast, but noted that government-funded transition costs are ". . .outside the Commission's purview. . ..."[58] Further, the costs funded by the DWR loan, which are recorded into the DCTRMA, including the PBDs, are reviewed through a process established by DWR and the Commission in accordance with Public Resources Code Section 25548.4.[59]

G. PG&E is Open to Working with Parties and the Commission on an Acceptable Schedule, But Requests that the Decision be Issued in a Timely Manner to Accommodate January 1, 2025 Rates

A4NR,[60] CalCCA,[61] and TURN[62] disagree with PG&E's proposed schedule. CalCCA proposes modifications to certain deadlines with no change to the final decision being issued on December 5, 2024. TURN proposes an alternate schedule with reply briefs and reply comments to the Fall Update in mid-January 2025. As further discussed below, submission of the proceeding record in mid-January 2025 prevents timely implementation of rates by the three IOUs until March 1, 2025, as the issuance of the final decision would likely occur late in the first quarter of 2025. A4NR does not propose an alternate schedule but opposes an abbreviated comment period.[63]

While PG&E does not oppose most of CalCCA's alternate schedule, and accepts the shortened period of time between rebuttal testimony and evidentiary hearing, as well as between evidentiary hearing and opening briefs, PG&E disagrees with the reduction between intervenor and rebuttal testimony by approximately one week. This reduction between intervenor and rebuttal testimony does not allow PG&E to evaluate and respond to intervenor proposals. In future years, PG&E is open to considering a more compressed schedule, but CalCCA's proposed

[58] D.23-12-036, p. 61.
[59] Pub. Res. Code § 25548.4(a)-(e).
[60] A4NR Protest, pp. 7-8.
[61] CalCCA Protest, pp. 17-19.
[62] TURN Protest, pp. 5-7.
[63] Rule 14.6(b) allows the parties in the proceeding to stipulate to a shortened comment period. In the past, this has been common practice in ERRA Forecast proceedings, including PG&E's ERRA Forecast proceedings, given the timing constraints between the anticipated Proposed Decision date and the need for a January rate change. See *Assigned Commissioner's Scoping Memo and Ruling* issued in A.22-05-029, August 4, 2023, p. 5.

time period of approximately three weeks between intervenor and rebuttal testimony would not allow PG&E to fully evaluate all intervenor proposals. Thus, PG&E proposes a single revision to CalCCA's schedule regarding intervenor testimony, shown below.

Event	**PG&E Application Schedule**	**TURN Schedule**	**CalCCA Schedule**	**PG&E Modified Schedule**
Intervenor testimony served	July 8, 2024	Mid-August	Aug. 5, 2024	July 29, 2024
Rebuttal testimony served	Aug. 6, 2024	Mid-Sept.	Aug. 27, 2024	Aug. 27, 2024
Rule 13.9 Meet and Confer	Aug. 16, 2024	Late Sept.	Sept. 3, 2024	Sept. 3, 2024
Evidentiary Hearings (if needed)	Aug. 29, 2024	Mid-Oct. (30 days after rebuttal testimony)	Sept. 9, 2024	Sept. 9, 2024
Opening Briefs	Sept. 27, 2024	Mid-Nov.	Sept. 27, 2024	Sept. 27, 2024
Market Price Benchmarks issued	Oct. 1, 2024	Late Nov.	Oct. 1, 2024	Oct. 1, 2024
Update to Prepared Testimony	Oct. 8, 2024	Late Nov.	Oct. 8, 2024	Oct. 8, 2024
Comments to Update to Prepared Testimony	Oct. 21, 2024	Mid-Dec.	Nov. 8, 2024	Nov. 8, 2024
Reply Briefs and Reply Comments to Update to Prepared Testimony	Nov. 21, 2024	Mid-January 2025	Nov. 21, 2024	Nov. 21, 2024
Proposed Decision ("PD")	Nov. 2024		Nov. 2024	Nov. 2024
Comments on Proposed Decision	+ 5 days after PD		+ 5 days after PD	+ 5 days after PD

Reply Comments	+ 3 days after Comments on PD		+ 3 days after Comments on the PD	+ 3 days after Comments on the PD
Final Decision	Dec. 5, 2024		Dec. 5, 2024	Dec. 5, 2024

PG&E has concerns with TURN's schedule delaying the final decision. Delaying the final decision would delay rates for PG&E, as well as for SCE and SDG&E. The schedule presented in PG&E's Application is modeled after the schedule developed in coordination with the other IOUs and parties in R.23-01-007, based on a typical Energy Resource Recovery Account ("ERRA") forecast schedule. Further, any instructions or direction from the decision resulting from this Application for the subsequent March 2025 annual application would be difficult to incorporate depending on the issuance date of the final decision. PG&E continues to be open to working with parties and the Commission on an acceptable schedule that would allow rates to be implemented in a timely manner.

H. The Post-Proceeding True-Up Process is Not Included in the Scope of this Proceeding

CalCCA suggests the following issue be included in the proceeding:

> Whether PG&E's intended Tier 3 advice letter process to true-up 2025 forecast revenue requirement and rates with actual costs, billed revenues, IOU remitted PG&E revenues and CAISO market revenues will allow parties a sufficient opportunity to conduct an audit-level review of PG&E's entries.[64]

This proposed issue is outside the scope of the annual DCPP extended operations cost forecast proceeding and should not be included. SB 846 expressly directs "a subsequent true-up to actual costs and market revenues for the prior calendar year via an expedited Tier 3 advice letter process."[65] This process was adopted by D.23-12-036.[66] The true-up will be addressed through the Tier 3 advice letter process where parties have the opportunity to participate. PG&E anticipates submitting the true-up advice letter for actual 2025 recorded costs and revenues in the

[64] CalCCA Protest, pp. 15-16.
[65] Pub. Util. Code § 712.8(h)(1).
[66] D.23-12-036, OP 4, p. 136.

first quarter of 2026.[67] PG&E anticipates submitting the true-up advice letter for actual 2025 recorded costs and revenues in the first quarter of 2026. PG&E also notes that DCPP's actual recorded costs are not subject to further reasonableness review as long as its costs are within 115 percent of its forecast.

I. PG&E's Inclusion of Societal and GHG-Free Benefits is Consistent with the Purpose of SB 846 to Promote Grid Reliability and State GHG Targets

TURN asserts that "PG&E inappropriately includes Greenhouse Gas (GHG) benefits calculated at the social cost of carbon in an effort to demonstrate the cost-effectiveness of extended operations at Diablo Canyon" and "does not appear to have endorsed this approach for zero carbon resource evaluation in any other Commission proceeding."[68] PG&E disagrees with TURN's characterization of its analysis. In D.23-12-036, the Commission expressly noted its intent to retain its authority to evaluate the prudence of DCPP's extended operations. PG&E does not include societal benefits in its revenue requirement or cost recovery request. Rather, the analysis is informational and consistent with the intent of the Legislature in passing SB 846 for grid reliability benefits and to meet the state's GHG-emissions reduction goals.

III. CONCLUSION

PG&E looks forward to further collaboration with parties in this proceeding.

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[67] Consistent with Commission's two decade's long regulatory process for the IOU's Assembly Bill 57 cost recovery (otherwise known as ERRA), D.23-12-036 adopted PG&E's proposal for a prospective annual forecast of costs and revenues followed by a presentation of under- or over-collected balances at the conclusion of the record period. D.23-12-036, OP 4; *see also*, discussion, pp. 99-103.

[68] TURN Protest, p. 3.

Respectfully Submitted,

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Date: May 20, 2024

ATTACHMENT A

DOCKETED	
Docket Number:	21-ESR-01
Project Title:	Resource Planning and Reliability
TN #:	256170
Document Title:	Staff Report - Senate Bill 846 Diablo Canyon Power Plant Extension Cost Comparison
Description:	California Energy Commission STAFF REPORT Senate Bill 846 Diablo Canyon Power Plant Extension Cost Comparison Comparison to Alternative Portfolio of Resources Consistent with Greenhouse Gas Reduction Goals
Filer:	Xieng Saephan
Organization:	California Energy Commission
Submitter Role:	Commission Staff
Submission Date:	5/3/2024 2:48:57 PM
Docketed Date:	5/3/2024

CALIFORNIA ENERGY COMMISSION

CALIFORNIA NATURAL RESOURCES AGENCY

California Energy Commission

STAFF REPORT

Senate Bill 846 Diablo Canyon Power Plant Extension Cost Comparison

Comparison to Alternative Portfolio of Resources Consistent with Greenhouse Gas Reduction Goals

May 2024 | CEC-200-2023-013-SF

California Energy Commission

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ACKNOWLEDGEMENTS

The authors express appreciation to the staff at the California Energy Commission for their review and contributions to this report. The California Energy Commission would also like to acknowledge support from staff at Guidehouse, Inc. on the technical analysis.

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ABSTRACT

The *Senate Bill 846 Diablo Canyon Power Plant Extension Cost Comparison – Comparison to Alternative Portfolio of Resources Consistent with Greenhouse Gas Reduction Goals* addresses a requirement in Senate Bill 846 (Dodd, Chapter 239, Statutes of 2022) (SB 846). This requirement specifies that the California Energy Commission (CEC) must determine whether extended operations of the Diablo Canyon Power Plant, compared to a portfolio of other feasible resources available for calendar years 2024 to 2035, is consistent with the greenhouse gases emissions reduction goals of Section 454.53 of the Public Utilities Code.

Keywords: Reliability, Diablo Canyon Power Plant, demand side resources, supply side resources, extreme events, climate change, reliability assessments

Please use the following citation for this report:

Erne, David and Chie Hong Yee Yang. May 2024. *SB 846 Diablo Canyon Power Plant Extension Cost Comparison*. California Energy Commission. Publication Number: CEC-200-2023-013-SF.

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Diablo Canyon Power Plant and SB 846 Overview

Diablo Canyon Power Plant (DCPP) consists of two nuclear reactors (Units 1 and 2) that produce a total of about 18,000 gigawatt-hours (GWh) of electricity annually, or 2.2 gigawatts (GW) of net peak capacity. PG&E is the holder of Facility Operating License Nos. DPR-80 (Unit 1) and DPR-82 (Unit 2). Each license authorizes the operation of DCPP units 1 and 2, set to expire by the end of 2024 and 2025, respectively. While planning for the replacement for DCPP has been ongoing since 2016, CPUC ordered load-serving entities (LSEs) in 2021 to procure at least 2,500 MW of zero-emitting resources to replace DCPP by June 1, 2025.

As described in the (DCPP Power Plant Extension Report) issued by the CEC in March 2023, there have been delays with resources coming online. Recent supply chain constraints in the market for solar, wind and energy storage resources and development delays (for example, interconnection and permitting), as well as increasingly frequent and more intense climate-driven extreme weather events, have resulted in risks to new resources coming online as planned and overall system reliability upon the retirement of DCPP. These challenges result in an upper limit to what resources can be brought on-line in a given time frame. Thus, maintaining grid reliability during the increasingly frequent extreme weather events may require the delay and careful planning of the retirement of DCPP or a significant increase in demand-side resources that are not subject to the same supply chain and interconnection challenges.

Senate Bill 846 (Dodd, Chapter 239, Statutes of 2022) (SB 846) notes that seeking to extend DCPP operations is the policy of the Legislature because it is prudent, cost effective, and in the best interest of California electricity customers. As such, SB 846 creates an option to extend DCPP operations by five years with a $1.4 billion loan provided by the state. In parallel to this extension, SB 846 calls for the California Energy Commission (CEC) to "present a cost comparison of whether extended operations at the Diablo Canyon powerplant compared to a portfolio of other feasible resources available for calendar years 2024 to 2035, inclusive, is consistent with the greenhouse gases emissions reduction goals of Section 454.53 of the Public Utilities Code. As part of this comparison, the CEC shall evaluate the alternative resource costs, and shall make all evaluations available to the public within the proceeding docket" by September 30, 2023. However, as described in this report, there are no supply resources incremental to those already begin procured that can be brought on-line before the planned 2024 and 2025 retirements of the DCPP units to meet the like-for-like energy generation of 18,000 GWh per year. This report describes the analysis conducted on the technical potential and costs of alternative resources against extending DCPP.

Given that the operational licenses of DCPP Units 1 and 2 are set to expire by the end of 2024 and 2025, respectively, and the state is facing near-term potential for grid reliability issues from climate change impacts, this report evaluates resources that can support grid reliability at the planned retirement dates However, it should be noted that on December 15, 2023, the CPUC issued Decision 23-12-036 conditionally approving the extended operations at Diablo

Canyon powerplant pursuant to SB 846 until October 31, 2029 for Unit 1 and October 31, 2030 for Unit 2.[1]

On December 19, 2023, the U.S. Nuclear Regulatory Commission (NRC) staff determined the license renewal application submitted by Pacific Gas & Electric on November 7, 2023, contained sufficient information to formally docket the application and begin the detailed safety and environmental reviews. With the docketing of the application, the reactors' operating licenses will remain in effect under an exemption to NRC regulations until the review is complete. A copy of the Diablo Canyon license renewal application is available online and publicly at the San Luis Obispo Library at 995 Palm Street, San Luis Obispo.[2] NRC license renewals typically take 18 – 22-months after submittal.

Resource Eligibility Criteria

Resource eligibility criteria were developed to identify resources to replace DCPP generating capacity and energy production in alignment with legislative requirements and DCPP characteristics. Supply and demand resources that satisfy the following criteria were further evaluated to potentially replace DCPP:

- **Zero-carbon:** Resources that produce no carbon emissions, similar to DCPP operations and consistent with the greenhouse gas (GHG) emission reduction goals.
- **Does not compete with Integrated Resource Plan (IRP) procurements:** Resource types incremental to, and not identified in, planned procurements to prevent increased costs in the market for resources already being procured by load-serving entities.
- **Grid value:** Resources that can provide the grid with consistent energy production throughout the day and reliable power during net-peak periods.

Diablo Canyon Costs

At the direction of the California Public Utilities Commission (CPUC), Pacific Gas and Electric (PG&E) submitted testimony presenting historical and forecast costs associated with potential improvements, day-to-day operations, and extended operations to be $736 million in 2023, $969 million in 2024, and $1.4 billion in 2025. These are preliminary cost estimates and may grow with additional planning and implementation. The costs presented by PG&E have been contested as being inaccurate by comments submitted in response to the draft of this report. This report does not reach any findings with respect to how long it may be cost-effective or prudent to operate DCPP.

SB 846 includes a provision that allows PG&E to access a $1.4 billion loan from the state's general fund to help extend DCPP operations, which include one-time expenditures such as capital, operating, relicensing, transition, and fuel costs. Through the SB 846 loan, PG&E could seek to recover $42 million in 2022, $381 million in 2023, $408 million in 2024, $210 million in 2025, and $58 million in 2026 for costs associated with extending the operation of DCPP,

1 https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M521/K496/521496276.PDF

2 The potential costs associated with PG&E's license renewal application and Diablo Canyon Independent Safety Committee recommendations regarding seismic safety and deferred maintenance are not included in this report.

which is a portion of the annual total forecasted costs above. PG&E will need to obtain these funds from the Department of Water Resources in advance of actual expenditures.
This report evaluates alternative resources against anticipated incurred costs of a DCPP extension. Therefore, it is noted that PG&E would need to request funds before costs are incurred in order to secure necessary materials and services.

Furthermore, PG&E applied for funding from the U.S. Department of Energy's Civil Nuclear Credit Program. DCPP received conditional federal funding under the DOE's new nuclear credit program. In November 2022, the DOE approved conditional funding of up to $1.1 billion to prevent the closure of DCPP. For the analysis in this report, CEC has compared alternatives to the $1.4 billion state loan.

When evaluating potential extended retirement dates, a robust additional analysis of the cost-effectiveness and prudence of DCPP extended operations should be performed based on updated DCPP cost recovery requests.

Alternative Resource Scenarios

Resources were evaluated for their ability to replace DCPP's full energy production in a **like-for-like** manner (18,000 gigawatt-hours [GWh]/year) or DCPP's **net peak** capacity (2.2 GW). Three scenarios were developed:

- The **supply scenario** evaluates supply resources that can provide consistent energy throughout the day to directly replace DCPP energy generation in a **like-for-like** manner.
- The **demand scenario** evaluates a combination of demand and distributed resources that can replace DCPP **net peak** capacity when operated together within a virtual power plant (VPP) construct.
- The **demand + supply scenario** evaluates demand and supply resources, particularly long-duration energy storage, that can replace the **net peak** capacity for DCPP.

Only resources that align with all resource eligibility criteria were evaluated for technological potential, cost, and project lead time in these scenarios.

Conclusions

The analysis shows that there are no supply resources that can be brought on-line before the planned 2025 retirement of DCPP to meet the like-for-like energy generation of 18,000 GWh per year. This situation is due to technology characteristics and the time required to develop and interconnect the projects but also due to the technology maturity of some resources. While there are about 500 MW of demand-side resources that could be deployed by 2025, there is no mix of resources that can adequately replace the 2.2 GW of net peak capacity of DCPP by 2025.

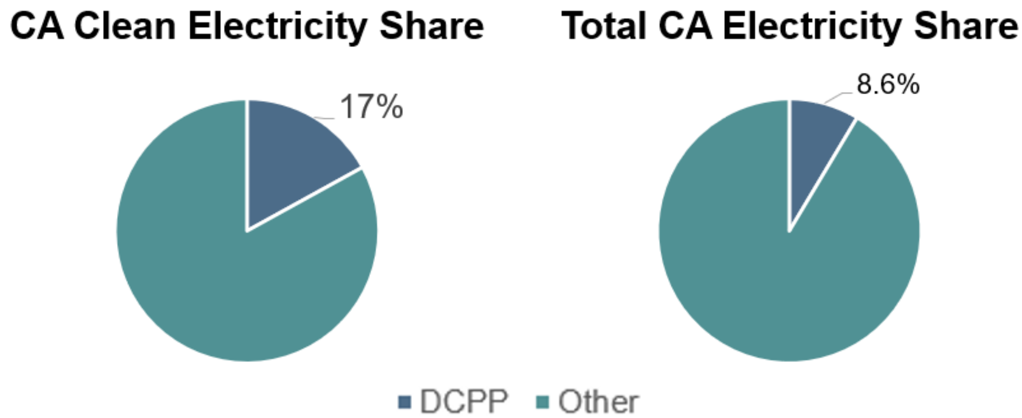
However, continued investments by LSEs in clean resources to meet IRP procurement orders, which includes resources to replace DCPP, can position the state to replace the energy and capacity provided by DCPP by or before 2030. This report does not come to any conclusion how long it would be cost effective and prudent to extend DCPP operations. Complementary investments in demand-side resources and long-duration energy storage would bolster the state's position to maintain reliability with DCPP by or before 2030 while promoting resource diversity.

CHAPTER 1: Introduction

Diablo Canyon Power Plant and SB 846 Policy Background

The Diablo Canyon Power Plant (DCPP) is a nuclear power plant near San Luis Obispo that is owned and operated by Pacific Gas and Electric Company (PG&E). The DCPP consists of two nuclear reactors (Units 1 and 2) that began operation in May 1985 and March 1986, respectively. DCPP produces about 18,000 gigawatt-hours (GWh) of electricity annually, which is about 9 percent of California's current in-state generation and 17 percent of California's zero-carbon electricity, as seen in Figure 1: DCPP Electricity Shares in California. DCPP reactor units are licensed by the United States Nuclear Regulatory Commission (NRC) to operate until November 2, 2024 (Unit 1), and August 26, 2025 (Unit 2).[3]

Figure 1: DCPP Electricity Shares in California



Source: Senate Bill 846, figure developed by Guidehouse for this report

In November 2009, PG&E submitted a license renewal application for Units 1 and 2 of DCPP to extend the units for another 20 years past the end of the current expiration dates: Unit 1 in November 2024 and Unit 2 in August 2025. On March 7, 2018, PG&E requested to withdraw the license renewal application based on projected energy demands and other economic factors in California. The California Public Utilities Commission (CPUC) approved PG&E's resource planning decision to withdraw the license renewal application review in a decision dated January 11, 2018. Subsequent to withdrawing its license renewal application, PG&E has stated that it has begun decommissioning planning.

3 Erne, David and Mark Kootstra. 2023. *Diablo Canyon Power Plant Extension – CEC Analysis of Need to Support Reliability.* California Energy Commission. Publication Number: CEC-200-2023-004. Available at https://www.energy.ca.gov/publications/2023/diablo-canyon-power-plant-extension-cec-analysis-need-support-reliability.

In the CPUC's Decision Requiring Procurement to Address Mid-Term Reliability,[4] the CPUC ordered load-serving entities to procure 2,500 MW of zero-emitting generation, generation paired with storage, or demand response resources by June 1, 2025, to replace DCPP.

On September 2, 2022, the State of California enacted Senate Bill 846 (SB 846, Dodd, Chapter 239, Statutes of 2022). This law invalidated the 2018 CPUC decision to approve termination of PG&E's license renewal application and retirement of DCPP Units 1 and 2 and directed the CPUC to establish new retirement dates conditioned on further action by the Nuclear Regulatory Commission.[5] SB 846 includes the following:

- Preserves the option of continued operations of DCPP "for an additional five years may be necessary to improve statewide energy system reliability and to reduce the emissions of greenhouse gases while additional renewable energy and zero-carbon resources come online, until those new renewable 1 and zero-carbon resources are adequate to meet demand."
- "Accordingly, it is the policy of the Legislature that seeking to extend the Diablo Canyon power plant's operations for a renewed license term is prudent, cost-effective, and in the best interest of California's electricity customers."
- States the intent of the Legislature to make available a $1.4 billion loan from the general fund to the Department of Water Resources to continue operations of DCPP Unit 1 until no later than November 1, 2029, and Unit 2 until no later than November 1, 2030.
- Requires that the CPUC not include and "disallow a load-serving entity from including in their adopted integrated resource plan the energy, capacity, or any attribute from (DCPP) Unit 1 beyond November 1, 2024, or Unit 2 beyond August 26, 2025."
- Requires the CPUC to set new retirement dates for the Diablo Canyon power plant, conditioned upon the United States Nuclear Regulatory Commission extending the operating licenses of the power plant by December 31, 2023.
- Requires the CEC to determine whether the state's electricity forecasts for 2024–2030 "show potential for reliability deficiencies if Diablo Canyon Power Plant operations are not extended beyond 2025, and whether extending operations to at least 2030 is prudent to ensure reliability and consistency with the state's emission reduction goals."
- Requires the CEC to "present a cost comparison of whether extended operations at the Diablo Canyon powerplant compared to a portfolio of other feasible resources available for calendar years 2024 to 2035, inclusive, is consistent with the greenhouse gases emissions reduction goals of Section 454.53 of the Public Utilities Code. As part of this comparison, the CEC shall evaluate the alternative resource costs, and shall make all evaluations available to the public within the proceeding docket" by September 30, 2023.

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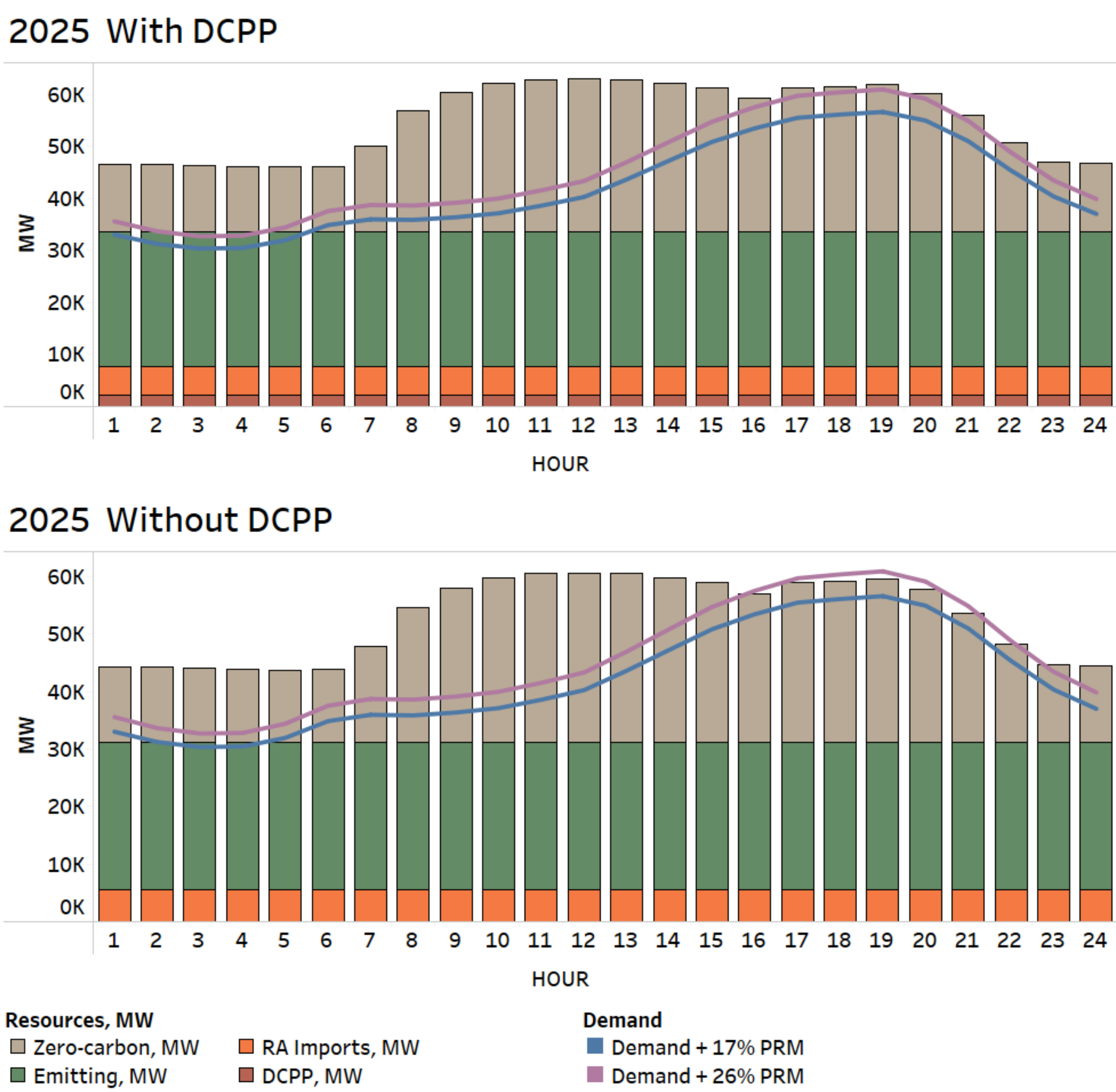
4 Decision Requiring Clean Energy Procurement for Mid-Term Reliability, California Public Utilities Commission, D21-06-035, June 24, 2021

5 Nuclear Regulatory Commission, Docket Nos. 50-275 and 50-323, Pacific Gas and Electric Company, Diablo Canyon Power Plant, Units 1 and 2 Exemption.

The key driver for SB 846 was to support grid reliability. The California grid is facing challenges, such as climate change (for example, extreme heat, extreme drought, and wildfire) supply chain issues impacting resource build-out, and interconnection timelines. The supply chain and interconnection challenges result in an upper limit to what can be brought on-line in a given time frame regardless of how much additional procurement is ordered. Thus, DCPP was identified as an incremental resource to what is already projected to come on-line, and that provides reliable electricity output for California's grid while being a clean-energy resource.

Figure 2: 2025 Projected Capacity With and Without DCPP Figure 2 shows the impact of DCPP on projected 2025 capacity within the California Independent System Operator (California ISO) system when compared to the CEC's demand forecast. By applying 24-hour resource profiles to projected capacity for all California ISO supply resources, Figure 2: 2025 Projected Capacity With and Without DCPP demonstrates DCPP's effect on the net-peak period during the max-peak day in September 2025, where there is greater chance of supply shortfall under extreme conditions (Demand + 26 Percent PRM).

Figure 2: 2025 Projected Capacity With and Without DCPP



Note: Figures were created using data from [Joint Agency Reliability Planning Assessment: SB 846 Quarterly Report and AB 205 Report](#).

Source: CEC staff with CPUC and California ISO data

SB 846 Approach and Considerations

This report evaluates the feasibility, cost, and potential of alternative resources, with similar characteristics as DCPP. The two characteristics considered are 18,000 GWh/year energy production (9,000 GWh/year from Unit 1, 9,000 GWh/year from Unit 2) and the 2.2 GW of DCPP generation capacity that supports reliability at net peak, the time of day in which total demand minus wind and solar generation is the highest. This net peak occurs in the evening hours, typically between 4 p.m. and 9 p.m., and is the time in which California is vulnerable to experiencing its most stressed grid conditions.

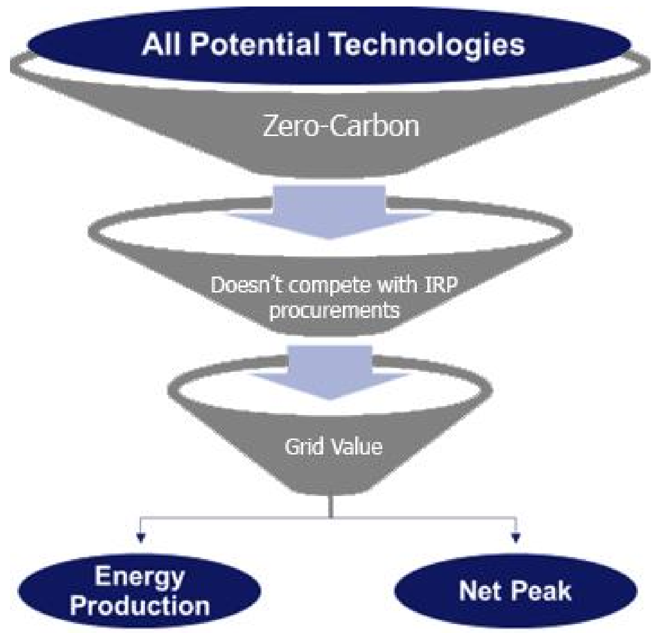
To align with the intent of SB 846 and evaluate the feasibility of resources to come on-line and replace DCPP before the current retirement dates, the CEC has focused its analysis on 2024 and 2025. These are the two years where the two reactors for DCPP may be decommissioned to compare to a set of resources that could potentially replace DCPP before it retires. CEC identified a broad set of resources ranging from demand side to supply side. Examples of these types of resources can be found in Tables 1-4. The CEC then filtered the list based on the ability of these resources to satisfy three resource eligibility criteria that align with DCPP characteristics. Resources that satisfy all criteria, which are described in Chapter 2, are eligible for analysis. These resources are grouped into supply resources and demand resources to ease evaluation of resources. All resources are evaluated based on the associated technical energy production potential, costs, and project lead time. Under SB 846, these resources are evaluated primarily to directly replace the 18,000 GWh of energy production from DCPP (like-for-like analysis) and secondarily replace the full capacity of DCPP during net-peak hours (net-peak analysis). For a like-for-like analysis, resources must provide consistent energy production to fully replace DCPP. Conversely, the net-peak analysis objective is less stringent, so more resources are eligible for consideration. Based on these two analysis objectives, resources are grouped into different scenarios catered to each objective.

CHAPTER 2:
Alternative Resource Characterization

Resource Eligibility Criteria

In alignment with legislative requirements and DCPP characteristics, the CEC has developed three resource eligibility criteria (eligibility criteria, or criteria) to identify resources to replace the generating capacity and energy production of the DCPP. Resources that satisfy all three criteria are further evaluated as part of an alternative portfolio to replace DCPP. Figure 3 demonstrates the resource filtering process based on the following criteria:

Figure 3: Resource Filtering on Eligibility Criteria



Source: Guidehouse analysis for this report

- **Zero-carbon**: Refers to resources that produce no carbon emissions. As stated in SB 846, DCPP supplies zero-carbon electricity, and an extension may be necessary until "new renewable energy and zero-carbon resources are adequate to meet demand."[6] Therefore, this criterion focuses on zero-carbon resources that can replace DCPP's capacity. Replacement with a fossil-fueled resource would result in increased GHG emissions. Therefore, flexible-fuel resources[7] are excluded from evaluation.
- **Integrated resource plan (IRP) procurements**: SB 846 notes the importance of having "sufficient, predictable resource procurement and development to avoid unplanned energy supply shortfalls by taking into account impacts due to climate change and other factors that can result in those shortfalls." Supply chain and interconnection delays have impacted the ability of new projects to come on-line as planned. As such, the extension of DCPP provides support for grid reliability until the new resources can come on-line to meet demand. SB 846 requires that the CPUC direct load-serving entities to not procure capacity and energy from the DCPP and report it in the integrated resource plan portfolios (IRPs).[8] This requirement ensures that LSEs will continue to procure clean energy resources as if DCPP were not

6 California Legislative Information. 2022. [Senate Bill No. 846](https://leginfo.legislature.ca.gov/faces/billTextClient.xhtml?bill_id=202120220SB846), Section 5 25548 (b), https://leginfo.legislature.ca.gov/faces/billTextClient.xhtml?bill_id=202120220SB846.

7 *Flexible-fuel resources* are technologies that have the flexibility of operating on different fuel types and potentially different fuel blends, including fossil fuels. These technologies are used as transitional technologies from fossil fuels to zero-carbon fuels.

8 California Legislative Information. 2022. [Senate Bill No. 1174](https://legiscan.com/CA/text/SB1174/id/2605746), California Public Utilities Code Section 454.52(f)(1) at https://legiscan.com/CA/text/SB1174/id/2605746.

on-line — allowing for a swifter replacement of the energy and capacity of DCPP with newly built clean power projects. Resources being pursued for procurement by LSEs are solar, wind, and energy storage. While these resources are coming on faster than ever in California, they are still not coming on quickly enough to meet demand due to interconnection delays, supply chain issues, and sheer competition for limited clean energy resources, resulting in a tight market for available solar, wind, and energy storage. Ordering more of these resources does not mean that they can come on-line quickly enough to provide the necessary grid support.

With recent supply chain disruptions and increased demand for materials for clean energy projects, the price of solar modules increased by 25 percent and wind turbines by 20 percent.[9] Ordering more clean energy supply in a tight market would likely have the unintended consequence of driving up prices further and creating further delays for current projects.

Therefore, this analysis excludes these conventional clean resources from consideration for further investment from the state, as state investments in conventional solar, wind, and battery storage would only exacerbate the tight market conditions[10] and interconnection bottlenecks in getting these clean resources on-line.

While resources that compete for IRP procurements are screened out, there may be opportunities for the state to further invest in resources that could meet energy demand but are not readily available or cost-effective today and are therefore not being procured by LSEs.

- **Grid value**: Focuses on resources that can provide the grid with similar reliability and electricity output as DCPP. The biggest values DCPP provides to the grid are consistent energy production throughout the day and reliable power during net-peak periods.
    - **Energy production (like-for-like)**: Since DCPP generates 18,000 GWh/year, a **like-for-like** replacement looks for resources that can replicate or exceed this energy production with zero emissions. This type of resource provides GHG-free energy to the grid at any time.
    - **Net Peak**: From a grid reliability perspective, DCPP provides 2.2 GW of capacity during net-peak periods (4 p.m. to 9 p.m.). To properly replace the net-peak capacity of DCPP, alternative resources are needed that can reliably satisfy the net-peak demand of the grid.

Resource Analysis

CEC staff evaluated alternative resources that met the above criteria for the ability to come on-line in 2024 and 2025 in line with the planned retirement of each DCPP generating unit to measure how those resources can contribute toward the California electricity grid by the time of DCPP's retirement. Staff evaluated alternative resources based on the following three characteristics:

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9 IEA - Clean energy supply chains vulnerabilities, via https://www.iea.org/reports/energy-technology-perspectives-2023/clean-energy-supply-chains-vulnerabilities

10Summer Reliability Workshop presentation, https://efiling.energy.ca.gov/GetDocument.aspx?tn=250179, slide 9.

- **Technological potential**: How much energy production (GWh) or capacity (GW) of this resource can be integrated annually?
- **Project lead time**: How long does this resource take to implement?
- **Cost estimate**: How much does this resource cost to acquire, integrate, and operate?

The CEC considered other resource-specific attributes such as supply chain limitations, permitting processes, and implementation requirements. CEC staff bundled these alternative resource characteristics into portfolios and compared them to DCPP cost and capacity characteristics.

Resource Categorization and Definitions

CEC staff separated the alternative resources under analysis into two resource classes — supply resources and demand resources. This section describes how the alternative resources for DCPP were considered and filtered based on the resource eligibility criteria.

Supply Resources

The supply resource class refers to resources that can generate electrical energy and provide capacity or energy to the electrical grid. Table 1 provides a complete list of the supply resources considered for this effort before filtering using the resource eligibility criteria.

Table 1: Complete Supply Resource List

Category	Supply Resources
Gaseous Fuel Generation	Combustion turbines/reciprocating engines (100% Clean Hydrogen)
Gaseous Fuel Generation	Fuel cells (100% clean hydrogen)
Gaseous Fuel Generation	Noncombustion and non-fuel-cell gas-fueled generator, such as linear generators (100% Clean Hydrogen)
Gaseous Fuel Generation	Fossil and nonclean hydrogen (reciprocating engines/combustion turbines, fuel cells, noncombustion and non-fuel-cell gas-fueled generators)
Gaseous Fuel Generation	Blended gas generation (reciprocating engines/combustion turbines, noncombustion, and non-fuel-cell gas-fueled generators)
Gaseous Fuel Generation	Renewable natural gas (RNG) combustion and fuel cells
Renewables	Solar (≥1 MW)
Renewables	Wind (onshore, floating offshore)
Renewables	Geothermal
Renewables	Small hydro (< 30 MW[11])
Long-Duration Energy Storage	Pumped storage hydro
Long-Duration Energy Storage	Electrochemical (e.g., flow, iron-air, zinc, sodium, excluding lithium-ion)
Long-Duration Energy Storage	Mechanical* (e.g., gravity-based, geo-mechanical, excluding PSH)
Long-Duration Energy Storage (LDES)	Thermal* (solid medium, liquid medium)
Other Energy Storage	Compressed air energy storage* (CAES)
Other Energy Storage	Energy storage (short duration, < 8 hours)

***These LDES options do not directly store electricity/electrons and require additional processing to provide electricity output.**

Source: Guidehouse analysis for this report

With this complete list of supply resources, CEC staff then applied the eligibility criteria to evaluate which technologies fit into the scope of SB 846 and are appropriate alternative resources to DCPP. Many conventional supply resources, such as gas-fired plants, were screened out because of incompatibility with the eligibility criteria. After filtering for zero-carbon supply resources, the biggest limiting factor was screening out resources that competed with procurement by electricity providers within the California ISO.

Renewable energy resources such as geothermal, hydropower, solar, and on/offshore wind are proven resources that may be important for California's energy future, but they were removed from this analysis as are the resources likely to be procured by CPUC jurisdictional LSEs for

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11 The CEC defines small hydro as any facility less than 30 MW, https://www.energy.ca.gov/data-reports/california-power-generation-and-power-sources/hydroelectric-power.

their compliance with IRP procurement requirements and POUs within California ISO to meet the state's carbon reduction goals and reliability need.

The rationale behind excluding geothermal, hydropower, solar, and on/offshore wind resources was the existence of considerable competition for their procurement. The current rigorous competition for clean energy projects necessitated a comprehensive screening process. Notably, this screening resulted in the exclusion of all technologies dependent on clean hydrogen, given that hydrogen production relies on the same pool of clean energy resources that have already been allocated for other purposes such as charging battery storage systems to support reliability during the net peak.

Flexible or blended gaseous fuel generation resources are not zero-carbon resources as they use fossil fuels to varying extents. Table 2 provides a list of the filtered supply resources and gives specific causes for the exclusion resources.

Table 2: Filtered Supply Resource List

Supply Resource	Included or Excluded?	Causes for Exclusion
Electrochemical (e.g., flow, iron-air, zinc, sodium, excluding lithium-ion)	Included	Not applicable.
Mechanical (e.g., gravity-based, geomechanical, excluding PSH)	Included	Not applicable.
Thermal (solid medium, liquid medium)	Included	Not applicable.
Solar (utility-scale > 5 MW, other 1 – 5 MW)	Excluded	Competes with IRP procurement orders
Wind (onshore, floating offshore)	Excluded	Competes with IRP procurement orders
Geothermal	Excluded	Competes with IRP procurement orders and GHG releases during operation
Small Hydro (< 30 MW)	Excluded	Competes with IRP procurement orders
Pumped Storage Hydro (PSH)	Excluded	Competes with IRP procurement orders
Compressed Air Energy Storage (CAES)	Excluded	Competes with IRP procurement orders
Energy Storage (short duration, < 8 hours)	Excluded	Competes with IRP procurement orders
Combustion Turbines/Reciprocating Engines – 100% clean hydrogen/ Renewable Gas (RNG)	Excluded	Hydrogen: Relies on clean energy resources for electrolysis. RNG/Biogas: Competes with IRP procurement orders

Supply Resource	Included or Excluded?	Causes for Exclusion
Fuel Cells	Excluded	100% clean hydrogen source not available at this time.
Noncombustion and Non-Fuel-Cell Gas-Fueled Generator	Excluded	100% clean hydrogen source not available at this time.
Fossil and non-clean hydrogen (reciprocating engines/combustion turbines, fuel cells, noncombustion and non-fuel cell gas-fueled generators)	Excluded	Not a zero-carbon resource
Blended Gas Generation (reciprocating engines/combustion turbines, noncombustion and non-fuel cell gas-fueled generators)	Excluded	Not a zero-carbon resource

Source: Guidehouse analysis for this report

Supply resources included in this analysis may compete with IRP procurement order requirements in the future as they become more technologically and commercially mature and costs drop to make them more competitive. As they are not competitive, they are included in this analysis. While LDES resources are called out by the CPUC's procurement orders, most of the near-term (1-2 years time horizon) are predominantly lithium-ion battery storage systems, which are intentionally excluded from this analysis to avoid competition with LSEs' ongoing procurement requirements.

Demand Resources

The demand resource class refers to resources that are installed and operated on the customer side to generate energy or manage load. Demand resources can be diverse in terms of technologies and end uses, as well as in terms of market design or program constructs. Demand resources encompass distributed energy resources (DERs), such as rooftop solar and storage and smart thermostats to provide demand response (DR). On a per customer basis, demand resources have relatively small contributions and may be subject to fluctuations in performance based on customer preferences or behavioral choices. However, aggregation, or collection, of demand resources, whether by LSEs or third-party DR providers (sometimes referred to as "aggregators"), can provide meaningful impacts. In addition, centralized control of several resources provides greater assurance of those resources being available when needed.

Given these considerations, demand resources are evaluated as aggregated resources through a virtual power plant (VPP) construct. For this analysis, VPPs are defined[12] as centrally

12 The VPP definition used in this SB 846 analysis was shaped by the Department of Energy and Brattle Group's VPP definitions.

controlled DERs from multiple customers to provide cost savings to customers and demand reductions that can benefit grid reliability. The VPP construct assumes DERs and other demand resources are controlled through aggregators and are visible to the grid operator. VPPs are composed of zero-carbon DERs and dispatchable DR and would be best suited to address the 2.2 GW capacity of DCPP during net-peak periods. As VPPs grow large enough and the market matures, they may ultimately be able provide energy support for the grid; however, there is a stronger case for capacity support. Table 3 lists the demand resources that were considered in the analysis.

Table 3: Complete Demand Resource List

Category	Demand Resources
Demand Response	Dispatchable DR measures[13]
Electric Vehicles	Electric vehicle control infrastructure (smart chargers, bidirectional chargers)
Distributed Generation	Solar + battery storage
Distributed Generation	Clean Hydrogen-powered distributed generation (reciprocating engines, fuel cells, noncombustion and non-fuel-cell gas-fueled generators)
Distributed Generation	Fossil, renewable gas generation, and non-clean hydrogen (reciprocating engines, fuel cells, noncombustion and non-fuel-cell gas-fueled generators)
Distributed Generation	Blended gas generation (reciprocating engines, noncombustion and non-fuel-cell gas-fueled generators)
Distributed Generation	Diesel or biodiesel generation (reciprocating engines, noncombustion and non-fuel-cell gas-fueled generators)

Source: Guidehouse analysis for this report

In alignment with the eligibility criteria, any aggregated demand resources to replace DCPP should be zero-carbon and provide generation or load reduction at net peak. Because certain demand resources depend on customer participation, such as DR and EV control, these resources better address capacity needs during peak and net-peak periods. From the full list of demand resources in Table 3: Complete Demand Resource List, the below distributed generation resources, in Table 4, were removed from consideration based on the reliance on fossil fuels and/or emissions of greenhouse gases or competition with IRP procurement orders. Table 4 shows the resulting list of eligible demand resources after this exclusion.

13 "Dispatchable DR measures" refer to various technologies that enable shedding or shifting of customer end use load when called upon, such as smart thermostats, smart water heating controls, industrial process load control, and agricultural pumping control.

Table 4: Filtered Demand Resource List

Category	Demand Resource	Included or Excluded	Causes for Exclusion
Demand Response	Dispatchable DR measures	Included	Not applicable
Electric Vehicles	Electric vehicle control infrastructure (smart chargers, bidirectional chargers)	Included	Not applicable
Distributed Generation	Solar + battery storage	Included	Not applicable
Distributed Generation	Clean hydrogen-powered distributed generation (fuel cells, reciprocating engines, noncombustion and non-fuel-cell gas-fueled generators)	Excluded	100% clean hydrogen source not available at this time.
Not applicable	Fossil, nonclean hydrogen, or renewable gas generation (reciprocating engines, fuel cells, noncombustion and non-fuel-cell gas-fueled generators)	Excluded	Not a zero-carbon carbon resource RNG/Biogas: Competes with IRP procurement orders
Not applicable	Blended gas generation (reciprocating engines, noncombustion and non-fuel-cell gas-fueled generators)	Excluded	Not a zero-carbon carbon resource
Not applicable	Diesel or biodiesel generation (reciprocating engines, noncombustion and non-fuel-cell gas-fueled generators)	Excluded	Not a zero-carbon carbon resource

Source: Guidehouse analysis for this report

The list of remaining demand resources in Table 4 includes dispatchable DR measures, electric vehicle control infrastructure, solar, and battery storage. These resources satisfy the resource eligibility criteria and were considered in the potential and cost analysis of a VPP-type construct to replace the 2.2 GW net-peak contributions of DCPP.

CHAPTER 3: Diablo Canyon Costs

New sources of state and federal funding have become available to keep DCPP operational via SB 846 and the U.S. Department of Energy's (DOE's) Civil Nuclear Credit Program. SB 846 includes a provision that allows PG&E to access a $1.4 billion loan from the state's general fund to help extend DCPP operations. Furthermore, PG&E applied for funding in the initial phase of the DOE's $6 billion Civil Nuclear Credit Program, meant to keep struggling nuclear power reactors open. DCPP was the first nuclear plant to receive conditional federal funding under the DOE's new nuclear credit program. In November 2022, the DOE approved conditional funding of up to $1.1 billion to prevent the closure of DCPP.[14] DOE continues to track the status of DCPP given the funding it has provided. Given state funding support and ongoing evaluation of the potential extension, SB 846 also requires PG&E to track all costs associated with continued and extended operations of DCPP.

PG&E Forecast Costs for DCPP

On April 6, 2023, the CPUC directed PG&E to submit testimony presenting "historical and forecast cost data (through 2030) for Diablo Canyon, focusing on costs associated with likely or potential improvements that might reasonably be required as part of the relicensing process."[15] The data found in PG&E's testimony,[16] presented in this chapter, are used as a baseline to compare DCPP extension costs and the cost of a mix of alternate resources in Chapter 4. These estimates were preliminary, and more detailed analysis of costs may be higher. PG&E will need to obtain these funds from the Department of Water Resources in advance of actual expenditures. This report evaluates alternative resources against anticipated incurred costs of a DCPP extension. Therefore, it is noted that PG&E would need to request funds before costs are incurred in order to secure necessary materials and services The Utility Reform Network[17] (TURN) conducted an independent analysis of DCPP extension costs, provided testimony in CPUC's proceeding, and provided a summary in CEC's reliability docket. TURN's testimony states that PG&E has underestimated the costs of extending DCPP operations.[18] Extension cost allocations, operational costs, and cost recovery will be addressed under established CPUC cost-recovery mechanisms and processes.[19] For this report, CEC used

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14 Civil Nuclear Credit Award Cycle 1 | Department of Energy.

15 California Public Utilities Commission. April 6, 2023. *Assigned Commissioner's Scoping Memo and Ruling*, Rulemaking to Implement SB 846 Concerning Potential Extension of DCPP Operations (R.23-01-007), https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M505/K462/505462882.pdf.

16 Pacific Gas and Electric Company. May 22, 2023. *Opening Testimony, Rulemaking to Implement SB 846 Concerning Potential Extension of DCPP Operations* (R.23-01-007), https://docs.cpuc.ca.gov/PublishedDocs/SupDoc/R2301007/6222/511023089.pdf.

17 TURN is a consumer advocacy organization and their website is https://www.turn.org/

18 The Utility Reform Network Comments – (SB 846 Diablo Canyon Power Plant Cost Analysis) – TURN testimony to CPUC on Diablo Canyon Costs available via https://efiling.energy.ca.gov/GetDocument.aspx?tn=251135

19 California Public Utilities Commission, 2023, Rulemaking 23-01-007, via https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M520/K614/520614035.PDF.

existing public information and subsequently updated the DCPP cost estimates based on PG&E's rebuttal testimony submitted July 28, 2023, for Rulemaking 23-01-007.[20] These cost estimates include costs for performance-based disbursements (total $136 million for 2024 and 2025) that will be reimbursed by the SB 846 loan program and additional extended operational fees and employee retention program expenses, which are estimated to be, on average, $295 million per year from 2024 to 2030. It does not include operational costs beyond 2025.

PG&E presented cost values for DCPP in the Electric Utility Cost Group (EUCG) accounting format, which is distinct to the general rate case (GRC)[21] accounting format, which uses the two major work categories (MWCs)[22] of expense and capital that the CPUC is most accustomed to using. PG&E claimed that EUCG cost definitions are designed to capture relevant holistic costs related to operating a nuclear generation plant. Moreover, PG&E claimed that EUCG categories tend to comingle with MWCs and thus allow for better industry benchmarking. Beyond EUCG, PG&E tracked capital, fuel, and refueling outage costs separately. Table 5 provides the complete list of the cost components PG&E used in its testimony, including EUCG components and others tracked separately, the descriptions, and ways that they map to MWCs typically used in GRCs, according to PG&E.

Table 5: Description of PG&E's Cost Components for DCPP and GRC MWC Mapping

Costs	Category	Details	GRC MWC Mapping
Nuclear Operating Costs (NOC), EUCG Cost Components	Engineering	Costs associated with study, design, and implementation of engineering	Maintain Plant Configuration
Nuclear Operating Costs (NOC), EUCG Cost Components	Loss Prevention	Costs include security, quality assurance/control, corrective action program & operating experience, safety and health, licensing, emergency preparedness, and dedicated dire responders	Loss Prevention, Manage Production, Nuclear Generation Fees

20 Pacific Gas and Electric Company, 2023, REBUTTAL TESTIMONY, via, https://docs.cpuc.ca.gov/PublishedDocs/SupDoc/R2301007/6511/515314717.pdf.

21 CPUC general rate cases (GRCs) are proceedings used to address the costs of operating and maintaining the utility system and the allocation of those costs among customer classes. GRCs are parsed into two phases: Phase I of a GRC determines the total amount the utility is authorized to collect, while Phase II determines the share of the cost each customer class is responsible and the rate schedules for each class. CPUC web page https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-rates/general-rate-case.

22 PG&E's GRC testimony is typically organized by its Lines of Business, in which expense and capital costs are presented separately. Expense and capital forecasts are then further broken down into Major Work Categories to represent different types of work for the LOB. Within each Major Work Category, individual projects are described for consideration by the Commission. Pacific Gas and Electric GRC Proceedings web page https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-rates/general-rate-case/pacific-gas-and-electric-grc-proceedings.

Costs	Category	Details	GRC MWC Mapping
Nuclear Operating Costs (NOC), EUCG Cost Components	Materials and Services	Costs include materials management & warehousing, contracts & purchasing, procurement engineering, and unneeded material disposal	Manage DCPP Assets
Nuclear Operating Costs (NOC), EUCG Cost Components	Fuel Management	Administrative and technical activities associated with the fuel-cycle process (contract, core designs, safety, monitoring performance, analyzing fuel market)	Maintain Plant Configuration
Nuclear Operating Costs (NOC), EUCG Cost Components	Operations	Activities associated with preparing and placing systems and components in and out of service to support normal and off-normal system operations and actions required to maintain the plant in sage operating conditions	Manage Production, Manage Environmental Operation
Nuclear Operating Costs (NOC), EUCG Cost Components	Support Services	Activities associated with information technology, business services, records management & procedures, human resources, housekeeping & facilities management, communications & community relations, nuclear offices, executives, management assistance and industry associations, employee incentive payments, insurance, payroll taxes, and pension & benefits	Manage DCPP Business, Manage DCPP Assets, Operational Management, Operational Support
Nuclear Operating Costs (NOC), EUCG Cost Components	Training – Develop and Conduct	Activities associated with development and conduction of training programs, including instructor preparation and instruction delivery time, production of class materials and assessment of the training	Nuclear Generation Fees, Operational Support
Nuclear Operating Costs (NOC), EUCG Cost Components	Work Management	Activities associated with planning & scheduling/outage management and maintenance.	Manage DCPP Assets, Operational Management, Operational Support
Other	Capital	Capital projects, including enhancements, infrastructure, information technology, capital spares, sustaining	DCPP Capital
Other	Outage	Refueling outage costs include the costs for labor, materials, equipment, and outside services	All MWC

Costs	Category	Details	GRC MWC Mapping
Other	Fuel	Provide and transport fuel (activities associated with provision and transportation of fuel including procurement, enrichment, conversion, and fabrication). Provide handling, storage, and disposal of fuel (activities associated with receiving and storing new fuel)	Energy Resource Recovery Account

Source: PG&E's Opening Testimony (May 22, 2023), CPUC Rulemaking to Implement SB 846 Concerning Potential Extension of DCPP Operations.

PG&E redacted cost data related to the following components: support services, total nuclear operating costs (NOCs), and fuel. Support services and total NOCs were excluded to protect market-sensitive fuel costs and prevent historical fuel costs from being derived from publicly available information. Fuel costs were excluded to avoid putting PG&E at a competitive disadvantage to other market participants, which could negatively impact PG&E customers. Table 6 and Table 7 provides a detailed cost breakdown of forecasted DCPP costs provided by PG&E.

Table 6: Detailed DCPP Forecasted Cost Components 2023–2025

Cost Component	2023 ($M)	2024 ($M)	2025 ($M)
Engineering	$44.4	$44.8	$39.0
Loss Prevention	$77.6	$78.2	$68.2
Materials and Services	$7.9	$7.9	$6.9
Fuel Management	$0.8	$0.8	$0.7
Operations	$76.3	$76.8	$67.0
Support Services	**REDACTED**	**REDACTED**	**REDACTED**
Training – Develop and Conduct	$9.4	$9.4	$8.2
Work Management	$108.1	$108.9	$192.0
Total Nuclear Operating Costs	**REDACTED**	**REDACTED**	**REDACTED**
Capital	$150.2	$150.0	$150.1
Outage	$46.8	$46.8	$97.0
Fuel	**REDACTED**	**REDACTED**	**REDACTED**
Other DCPP Costs	N/A	$222.6	$505.3
Additional Costs	N/A	$2.4	$5.4
Total Redacted Costs	**$214.2**	**$220.6**	**$264.0**
Total[23]	**$735.7**	**$969.2**	**$1403.8**

[23] As compared to the draft Diablo Canyon Power Plant Operations Assessment report published August 1, 2023, the final report is updated with cost data from the July 28, 2023, Rebuttal Testimony. This included changes to the "Other DCPP Costs" and "Additional Costs" categories. "Other DCPP Costs" are defined as costs and/or funding for DCPP have been established in statute for the extended operations of DCPP. "Additional Costs" are defined as cost allocations based on the 2023 General Rate Case (GRC) for DCPP for the retirement years of 2024

Note on redacted costs: Release of market sensitive information could put PG&E at a competitive disadvantage with regard to other market participants and could detrimentally impact all customers. Therefore, some cost details are not provided in their forecast.

Source: PG&E's Opening Testimony (May 22, 2023), CPUC Rulemaking to Implement SB 846 Concerning Potential Extension of DCPP Operations (updated with July 28, 2023, rebuttal testimony)

Table 7: Detailed DCPP Forecasted Cost Components 2026–2030

Cost Component	2026 ($M)	2027 ($M)	2028 ($M)	2029 ($M)	2030 ($M)
Engineering	$39.80	$41.20	$42.60	$44.10	$19.00
Loss Prevention	$69.50	$71.90	$74.40	$77.00	$33.20
Materials and Services	$7.10	$7.30	$7.60	$7.80	$3.40
Fuel Management	$0.70	$0.80	$0.80	$0.80	$0.40
Operations	$68.30	$70.70	$73.20	$75.70	$32.60
Support Services	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
Training — Develop and Conduct	$8.40	$8.70	$9.00	$9.30	$4.00
Work Management	$142.60	$147.60	$206.50	$158.10	$68.20
Total Nuclear Operating Costs	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
Capital	$154.30	$119.80	$124.00	$96.20	$20.80
Outage	$50.20	$51.90	$107.50	$55.60	$24.00
Fuel	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
Other DCPP Costs	$515.50	$460.40	$462.20	$454.60	$176.20
Additional Costs	$5.60	$5.80	$5.80	$5.8	$2.90
Total Redacted Costs	***$224.20***	***$232.10***	***$240.20***	***$248.90***	***$217.00***
Total[24]	**$1286.20**	**$1218.20**	**$1353.80**	**$1233.90**	**$601.70**

Note on REDEACTED costs: Release of market sensitive information could put PG&E at a competitive disadvantage with regard to other market participants and could detrimentally impact all customers. Therefore, some cost details are not provided in their forecast.

Source: PG&E's Opening Testimony (May 22, 2023), CPUC Rulemaking to Implement SB 846 Concerning Potential Extension of DCPP Operations (updated with July 28, 2023, rebuttal testimony)

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and 2025. "Other DCPP Costs" include performance-based disbursements, retention, volumetric fee, fixed fees, and liquidated damages while "Additional Costs include property and other taxes.

[24] As compared to the draft Diablo Canyon Power Plant Operations Assessment report published August 1, 2023, the final report is updated with cost data from the July 28, 2023, Rebuttal Testimony. This included changes to the "Other DCPP Costs" and "Additional Costs" categories. "Other DCPP Costs" are defined as costs and/or funding for DCPP have been established in statute for the extended operations of DCPP. "Additional Costs" are defined as cost allocations based on the 2023 General Rate Case (GRC) for DCPP for the retirement years of 2024 and 2025. "Other DCPP Costs" include performance-based disbursements, retention, volumetric fee, fixed fees, and liquidated damages while "Additional Costs" include property and other taxes.

DCPP Costs Used for Analysis

The NOC costs (including all costs except capital, outage, and fuel) represent an operational baseline or nonoutage routine annual cost profile. While fuel and outage costs were not included in the NOC category, the CEC assumed for the SB 846 analysis that all costs except capital costs are operating and fuel costs. Table 8 shows the capital expenditures (CAPEX) and operating expenditures (OPEX) and fuel values used in this SB 846 analysis to compare against scenarios of alternative resources.

Table 8: DCPP CAPEX and OPEX Values for SB 846 Analysis, in Millions of Dollars

Cost Component	2023	2024	2025
Capital Expenditures (CAPEX)	$150.2	$150.0	$150.1
Operating Expenditures (OPEX) and Fuel	$585.6	$594.4	$743.0

Source: PG&E's Opening Testimony (May 22, 2023), CPUC Rulemaking to Implement SB 846 Concerning Potential Extension of DCPP Operations

CHAPTER 4: Comparison of Alternative Resources to DCPP

Scenario Development Approach

Like-for-Like Analysis vs. Net Peak Analysis

The alternative resource comparison evaluates the extent to which alternative resources can replace the generating capacity of DCPP from an energy-production perspective and a net-peak-capacity perspective. First, under the energy-production perspective, or **like-for-like analysis**, only resources that can successfully participate in replacing the full energy production of DCPP are considered. These resources, in total, must be capable of replacing the full energy production of DCPP. Resources in the like-for-like analysis succeed in replacing DCPP only when they cumulatively generate 18,000 GWh/year, which is equivalent to the annual energy production of DCPP. The resources considered for the like-for-like analysis are carefully selected based on whether they can consistently produce energy in a manner like DCPP while satisfying all the resource eligibility criteria.

On the other hand, the **net-peak analysis** evaluates the ability for alternative resources to cover DCPP contributions to grid reliability, that is, the capacity contributions of the plant during net-peak periods. Under the net-peak analysis, resources must be able to provide consistent, reliable capacity during net-peak periods. Resources under the net-peak analysis succeed in replacing the net-peak generating capacity of DCPP when they can provide 2.2 GW, which is the full capacity of DCPP, during net-peak periods. With the like-for-like and net-peak analysis objectives in mind, CEC developed and analyzed a set of scenarios, each composed of different mixes of resources based on the associated ability to meet each objective.

Scenario Development

Based on the characterization of supply resources and demand resources and the like-for-like and net-peak analysis objectives, CEC developed three scenarios of alternative resources to replace DCPP. The first is the Supply Scenario, which consists of supply resources that can provide consistent energy throughout the day to directly replace DCPP generation and satisfy the requirements of a like-for-like replacement. The second and third scenarios, the Demand Scenario and the Demand-and-Supply Scenario, focus on satisfying the requirements of a net-peak replacement of DCPP. The Demand Scenario consists of only demand resources and evaluates the capabilities of these resources to replace DCPP during net-peak periods. The Demand-and-Supply Scenario consists of all demand resources and supply resources, including those that could not participate in the like-for-like analysis (that is, LDES), and evaluates which mix of resources can best replace the net-peak generating capacity of DCPP.

To complete the alternative resource comparison with DCPP, the analysis answered the following questions for each of the three scenarios:

1. Can the resources be implemented to replace the energy production or capacity (like-for-like or net peak) of DCPP before retirement? This question evaluates the ability to replace half the energy production or capacity by 2024 when the first unit is scheduled to retire, and the second half of energy production or capacity by 2025 when the second unit is schedule to retire. To answer this question, CEC quantified the annual

technological potential (in GWh or GW) of resources in each scenario, considering the project lead time required to develop and implement these resources.

2. What is the cost to implement these resource options? How does this cost compare to the cost of keeping DCPP operational? To answer these questions, CEC quantified the **costs** associated with developing the resources in each scenario.[25]

Like-for-Like Analysis – Supply Scenario

Supply Scenario Overview

The Supply Scenario seeks to address a like-for-like replacement for DCPP zero-carbon energy production (GWh) by evaluating resources capable of providing consistent zero-carbon energy over extended periods. To be considered a true like-for-like replacement, the Supply Scenario must cumulatively generate 18,000 GWh/year, equivalent to the annual energy production of DCPP. Many common supply resources were screened out because of incompatibility with the eligibility criteria. Many supply resources are commonly included in state planning and, therefore, in competition with what the CPUC ordered in the three procurement orders of IRP (that is, geothermal, small hydropower, compressed air energy storage) and are thus screened out. Clean, renewable hydrogen technologies are also screened out because of the need for additional resources such as solar and wind to generate the clean hydrogen. SB 846 is also seeking zero-carbon replacements to DCPP, so fossil gas generation, blended gas generation, and non-clean hydrogen technologies were excluded because they produce carbon emissions.

Supply Scenario Method and Evaluation

The supply resources included for analysis consist of long-duration energy storage technologies (LDES). LDES supply resources are utility-scale storage options that can provide more than four hours of continuous energy. However, LDES resources are unable to substitute for the ability of DCPP to provide energy as they are not generation resources . Rather than a like-for-like DCPP replacement, LDES paired with existing clean energy generation can help replace the 2.2 GW capacity of DCPP during net peak.

Large supply-side projects are vulnerable to external lead-time factors such as supply chain, permitting, and interconnection processes. Based on California ISO's Resource Interconnection Management System (RIMS) data, interconnection has taken an average of six years[26] for projects that have come on-line since 2010. Interconnection processes, which include study, procurement by load-serving entities, construction of the facility, and in some cases transmission upgrades, add to the overall lead times for projects. Overall, these long lead times remain a key consideration when planning for these technologies.

The California ISO Track 2 Straw Proposal[27] for the 2023 Interconnection Process Enhancements (IPE) initiative seeks to address the unprecedented influx of interconnection requests due to the rapid growth of clean energy development in California. While the IPE has

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25 CEC notes that operational costs for most renewable resources are lower than the historic operational costs for DCPP.

26 This is the elapsed time between interconnection application submittal and the date the system was on-line.

27 California ISO, 2023, 2023 Interconnection Process Enhancements, via https://www.caiso.com/InitiativeDocuments/Straw-Proposal-Interconnecton-Process-Enhancements-2023-Sep212023.pdf

potential to improve interconnection times, the approval and implementation could take most of 2024 which means it will not be available to help bring projects on-line by 2025.

Supply Scenario Takeaways

Gaseous fuel generation resources in the Supply Scenario are unable to provide any energy production by the end of 2025. California's clean hydrogen production, distribution, and storage shortfalls highly constrain Supply Scenario resources and prevent them from fulfilling DCPP energy production. As defined in the eligibility criteria, the Supply Scenario must generate 9,000 GWh/year in 2024 and an additional 9,000 GWh/year by 2025 to act as a like-for-like replacement to DCPP. Considering there is not a Supply Scenario that is projected to be operational as a portfolio in the next two years, the like-for-like analysis conveys that there are no direct replacements for DCPP before 2025, or until a steady flow of hydrogen becomes available.

Net Peak Analysis – Demand Scenario

Demand Scenario Overview

The Demand Scenario analyzes how a combination of demand resources could replace the 2.2 GW capacity of DCPP during net-peak periods. In considering a scenario composed of demand resources, CEC staff notes that centralized control of multiple resources provides greater assurance of those resources being available when needed. California has existing experience with controlling end uses and associated enabling technologies through VPP constructs in utility and third-party administered DR programs such as the Demand Response Auction Mechanism (DRAM), Capacity Bidding Program (CBP), Emergency Load Reduction Program (ELRP), and the Demand Side Grid Support (DSGS) program. In addition to these programs, utilities have been offering time-varying rates to modify customer behavior and shape loads to address grid needs (for example, time-of-use rates, critical peak pricing, real-time pricing).

Significant efforts are also underway to unlock greater potential from demand-side resources through widespread adoption of advanced rates, paired with enabling technologies, under CPUC's CalFUSE framework.[28] However, VPP constructs would need to scale significantly and quickly above existing levels to replace the 2.2 GW of capacity of the DCPP before the current retirement dates. For reference, the size of existing demand-side resources (available through DR programs and rates) is 3.1 GW–3.6 GW in 2022.[29] A breakdown of these existing resources is in Table 9.[30] These programs and rates were launched at different points in time and have achieved this level of capacity over time. For example, economic DR programs includes about 200 MW from DRAM, which launched in 2016, and about 40 MW from CBP, which launched in 2007. Emergency programs such as ELRP were launched in 2021.

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28 CalFUSE refers to the CPUC Staff Proposal for a California Flexible Unified Signal for Energy. See also CPUC proceeding R.22-07-005, Demand Flexibility Rates.

29 Neumann, Ingrid and Erik Lyon. May 2023. *Senate Bill 846 Load-Shift Goal Report*. California Energy Commission. Publication Number: CEC-200-2023-008. Available for download at https://efiling.energy.ca.gov/GetDocument.aspx?tn=250357&DocumentContentId=85095.

30 Ibid.

Table 9: Existing Demand-Side Resources

Demand Resource	Capacity (MW)
Load-modifying rates and programs	~650–1,000
Economic programs, integrated in California ISO market	670–825
Reliability programs, integrated in California ISO market	740
POU DR programs	210
Emergency programs	~1,200
TOTAL	**3,100–3,600**

Refer to CEC Load-Shift Goal Report for specific breakdown of each DR resource type.

Source: CEC Senate Bill 846 Load-Shift Goal Report

There are structural and policy barriers that need to be resolved before the full potential from demand-side VPP resources can be realized.[31] Also, mechanisms to value exports from behind-the-meter (BTM) DERs at a customer site do not exist, which restricts realization of the potential from these resources. In addition, there are performance challenges with DR programs, which can be attributed partly to customer fatigue and attrition resulting from extended multiday or multiweek periods of DR dispatch during high-demand periods in summer. Customer participation levels in DR programs are relatively low as the value proposition for customers is not clearly established. Based on the average realized DR performance of 67 percent in the California ISO market in recent years, a portfolio of demand resources should aim to reach 3.3 GW of procured capacity to replace the 2.2 GW capacity of DCPP.[32] Still, DR and other demand or distributed resources have contributed to alleviating grid emergencies in recent years. So, the Demand Scenario explores using such resources to replace the net-peak contributions of DCPP beyond what is expected to be procured in existing DR programs.

Demand Scenario Method and Evaluation

Characterizing the potential and cost from demand resources that could contribute to the analysis of the Demand Scenario required a more granular specification of the included resources listed in Table 4. Dispatchable DR measures is broad and encompasses a wide range of controllable end uses and potential DR technologies. Consequently, CEC staff further divided the DR measures category into the following end-use subcategories:

- Heating, ventilation, and air conditioning (HVAC) control
- Industrial process load control
- Agricultural load control

31 The CEC Load-Shift Goal Report discusses many of the barriers and challenges facing demand resources in California and includes a series of policy recommendations to increase load shifting and demand flexibility.

32 See California ISO *Demand Response Issues and Performance Report 2022* (overall average supply plan DR performance for high-demand summer days).

- Other end-use control

Table 10 lists the resources considered in the Demand Scenario, including this subcategorization of DR measures.

Estimates of the incremental net-peak achievable potential (MW) that each resource in Table 10 could contribute to a VPP construct by the end of 2025 were derived from the CEC's modeling and analysis for the Statewide Load-Shift Goal adopted in May 2023.[33] These estimates are based primarily on CEC forecast data and inputs from the Lawrence Berkeley National Laboratory (LBNL) California Demand Response Potential Study.[34]

The CEC Load-Shift Goal Report provides a comprehensive overview of the method, inputs, and assumptions used for the potential modeling. The Load-Shift Goal model forecasted hourly gross and net-peak load estimates and characterized the achievable potential from technical options to control end-use load. The hourly gross and net-peak load calculations used annual electricity consumption and renewable generation forecasts from the 2021 and 2022 IEPR forecasts (including load modifiers for energy efficiency, fuel substitution, and transportation electrification), along with hourly load shapes from the LBNL-Load model (which is based on California IOU AMI data). The characterization of achievable potential from demand-side resources included defining inputs such as projected saturation, cost-optimized participation fractions, and unit impacts, which were sourced from the LBNL California Demand Response Potential Study assumptions. The primary output from the Load-Shift Goal modeling was an estimate for 7,000 MW of cumulative achievable net-peak load reduction that could be attained from DR and other load-shifting mechanisms by 2030, which represents 3,400 MW to 3,900 MW of incremental growth above existing 2022 DR MWs in the state.

CEC staff used the results from the Load-Shift Goal modeling and performed additional analysis to arrive at the 2025 incremental estimated net peak achievable potential values shown for the DR, electric vehicle, and solar + battery storage resources in Table 10. The first adjustment to the load shift model was to break down the estimates for existing 2022 MWs to the technology and end-use levels, which was done by applying assumptions about the end uses targeted by existing California DR programs and rates. This application then allowed staff to estimate the incremental growth potential from 2022 to 2030 for each VPP component resource. Finally, incremental potential estimates for 2025 were derived by estimating growth ramps for each resource from existing 2022 levels to 2030 potential levels from the Load-Shift Goal estimate. For this exercise of determining how quickly the estimated potential for each VPP component can be realized, staff used the qualitative determination of current resource maturity shown in Table 10 (as either mature or emerging), which reflects existing technological maturity and saturation as well as the current ability to participate in VPP constructs. Based on these results, CEC determines that a portfolio of demand resources could feasibly be expected to contribute a maximum of about 725 MW of procured incremental net-

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33 The [CEC Load-Shift Goal Report]() addresses the requirement in SB 846 for the CEC to develop a statewide goal for load shifting to reduce net peak electrical demand. The CEC-adopted Load-Shift Goal is 7,000 MW of total load shift capacity (or 3,400 to 3,900 MW incremental growth relative above 2022) by 2030.

34 Gerke, Brian, Giulia Gallo, Sarah Josephine Smith, Jingjing Liu, Shuba V Raghavan, Peter Schwartz, Mary Ann Piette, Rongxin Yin, Sofia Stensson. 2020. *The California Demand Response Potential Study, Phase 3: Final Report on the Shift Resource through 2030*. Lawrence Berkeley National Laboratory.

peak capacity (or about 500 MW of realized potential)[35] by the end of 2025, which is insufficient to replace the reliability contributions of DCPP.

Table 10: VPP Resource Estimated Incremental Potential, 2025

VPP Resources	Resource Maturity	2025 Incremental Net Peak Achievable Potential (MW)
DR: Heating, Ventilation, and Air Conditioning (HVAC) Control	Mature	250
DR: Process Control	Mature	100
DR: Agricultural Control	Mature	100
DR: Other End-Use Control	Emerging	25
Electric Vehicles	Emerging	50
Solar + Battery Storage	Emerging	200
Hydrogen-powered Distributed Generation	Emerging	0
TOTAL (Achievable)	Not Applicable	**725**
TOTAL (Realized)	Not Applicable	**485**

Source: Guidehouse analysis for this report

Staff performed the cost assessment for the Demand Scenario using cost factors representing average per-kW upfront and ongoing incentive costs required to enroll and aggregate various demand resources into a VPP or DR program. Cost factors were sourced from the LBNL *2025 California Response Potential Study* and from a recent report published by the Brattle Group titled *Real Reliability: The Value of Virtual Power*.[36] For demand resources contributing, ongoing incentives (for example, annual or seasonal participation payments) are required to build a VPP or DR resource in addition to any upfront equipment, installation, or recruitment costs.

Table 11 shows a summary estimate for the cost required to achieve about 725 MW of procured incremental net-peak capacity (about 500 MW of realized potential) from an example composition of demand resources in a VPP, which is aligned with the estimated incremental achievable potential by the end of 2025. The estimate is an upfront capital cost between $230 million and $330 million plus recurring annual incentive costs of about $50 million–$65 million per year.

35 Considering the average realized DR performance of 67 percent in the California ISO market in recent years (from California ISO Demand response issues and performance report 2022), 725 MW of procured capacity could be expected to yield roughly 500 MW of realized impact.

36 Brattle Group. 2023. *Real Reliability: The Value of Virtual Power*, https://www.brattle.com/real-reliability/.

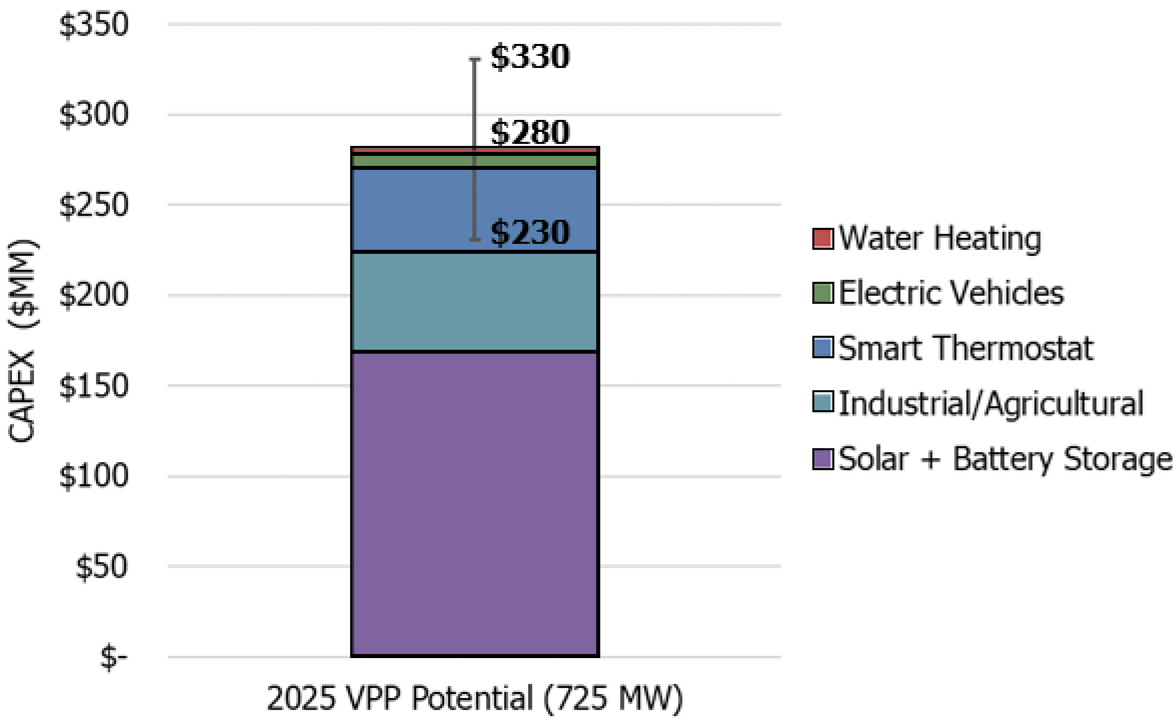
Table 11: VPP Potential and CAPEX Costs for 2025

Representative VPP Resource	Capacity (MW)	CAPEX Only ($M)
Smart Thermostat	250	30–60
Water Heating	25	1–2
Electric Vehicles	50	3.5–12
Solar + Battery Storage	200	145–195
Industrial/Agricultural	200	50–60
TOTAL	**725**	**230–330**

Source: Guidehouse analysis for this report

To obtain an aggregate estimate for the cost of demand resources in a VPP, an assumption must be made about the relative contributions of various end-use or control technologies within a representative VPP. In Table 11, the allocated capacity of each representative VPP resource is based on the relative size of overall load-shift potential as calculated for the development of the Statewide Load-Shift Goal. Figure 4 illustrates ways that the estimated total capital expenditures (CAPEX) are broken down among the constituent end uses.

Figure 4: Representative 725 MW VPP CAPEX for 2025



Source: Guidehouse analysis for this report

Demand Scenario Takeaways

Overall, the Demand Scenario analysis indicates that there is about 725 MW of procured incremental net-peak capacity that could be achieved from demand resources by the end of 2025. The estimated 725 MW of procured capacity could be expected to yield nearly 500 MW of realized potential, considering historical DR performance in the California ISO market. On an ongoing per MW basis, the demand resources do appear to be less expensive than DCPP. However, the size of the resource is insufficient to replace the 2.2 GW of capacity from DCPP by 2025. Achieving the estimated 725 MW procured capacity by the end of 2025 would require an upfront capital investment between $230 million and $330 million.

Net-Peak Analysis – Demand + Supply Scenario

Demand + Supply Scenario Overview

The Demand and Supply Scenario focuses on ways that demand and supply resources can be leveraged to replace the net-peak capacity of 2.2 GW for the DCPP. This scenario looks to evaluate an optimal combination of resources that can achieve the DCPP net-peak capacity at the lowest cost and fastest time frame. As seen in the Demand Scenario, demand resources can contribute only about 500 MW of realized capacity during net-peak periods by the end of 2025. Meanwhile, the Supply Scenario evaluates only resources that can address the like-for-like analysis, not the net-peak analysis that this scenario looks to address. LDES was excluded from the Supply Scenario for the inability to act as a reliable resource for all hours of the day, thus being unable to replace DCPP in the like-for-like analysis. Moreover, LDES is not a generation resource and is carbon-free only if the generation charging LDES is carbon-free. However, LDES can be an important capacity-contributing resource under the net-peak analysis based on the ability to provide consistent power across a full net-peak period.

Therefore, the Demand and Supply Scenario analysis includes LDES as supply resources, as seen in Table 12.

Table 12: Long-Duration Energy Storage (LDES) Resources Considered

LDES Resources
Electrochemical (e.g., flow, iron-air, zinc, sodium, excluding lithium-ion)
Mechanical (e.g., gravity-based, geomechanical, excluding PSH)
Thermal (solid medium, liquid medium)

Source: Guidehouse analysis for this report

Demand and Supply Scenario Method and Evaluation

The analysis for demand resources was completed in the Demand Scenario, so this section focuses on the LDES resources that have not been evaluated, noting that lithium-ion was excluded from this analysis to avoid competition with IRP procurement orders and expected POU procurement. To fully understand the technological potential of LDES technologies in California, it is necessary to understand what is being planned in the state.

- The CEC has a Long-Duration Energy Storage Program that is providing $140 million to support LDES development in the state.[37]
- The CPUC has ordered the procurement of 1,000 MW of new LDES by 2028.[38]

The resources in Table 12 vary in terms of commercial maturity and availability but are largely still nascent in the market for durations long enough to satisfy net-peak periods readily and reliably, above eight hours within the period before 2025.[39] Furthermore, the technical project lead time to install these technologies at the scale required for this analysis ranges from one to three years with supply chain constraints playing a critical role in this timeline. This technical project lead time does not reflect external lead times factors, such as time required for interconnection. As evidenced in the Supply Scenario, interconnection has taken an average of six years for projects that have come on-line since 2010. Thus, LDES resource lead times may be affected by a combination of the ability to scale these resources in the next two years, project lead times, and interconnection timelines. Therefore, achieving incremental capacity beyond what is already planned in the state may require more efforts and funding opportunities.

Demand and Supply Scenario Takeaways

The addition of LDES resources for consideration in this scenario, in principle, provides potential to reach the net-peak capacity of DCPP that cannot be met by resources considered

37 Minutes of the June 16, 2023, CEC Business Meeting, pg. 4. Information item 4: Current Activities of the Long-Duration Energy Storage (LDES) Program

38 CPUC's IRP proceeding [R.] 20-05-003. Decision Ordering Supplemental Mid-Term Reliability Procurement (2026-2027) and Transmitting Electric Resource Portfolios to the California Independent System Operator for the 2023-2024 Transmission Planning Process

39 Based on technology maturity and availability information gathered from interviews with LDES technology developers conducted by Guidehouse Insights, Guidehouse's internal research branch. The duration of 8 hours was deemed as an appropriate target to classify energy storage as long duration in coordination with CEC.

in the Demand Scenario or the Supply Scenario. Nevertheless, given the difficulty to achieve incrementality, extended project lead times, and the current constraints on scale, it is unlikely that LDES will provide any additional capacity in this Demand + Supply Scenario by the end of 2025.

Alternative Resource Replacement of DCPP Takeaways

This report evaluates the potential for alternative resources to replace the energy production and power capacity of DCPP before the end of 2025, when DCPP is up for extension or decommissioning. Alternative resources were evaluated based first on the associated competition with IRP procurement and carbon intensity, and secondly on technical energy production potential, costs, and project lead time. First, staff evaluated alternative resources under the like-for-like analysis to replace the energy production of the DCPP. A full like-for-like replacement of DCPP requires a set of resources capable of providing 18,000 GWh/year of consistent, zero-carbon energy in total. The like-for-like analysis was highly selective because resources must satisfy the resource eligibility criteria and provide consistent energy, like DCPP, throughout the day.

On the other hand, the net-peak analysis was performed to evaluate the ability of alternative resources to cover the contributions of DCPP to grid reliability, that is, the capacity during net-peak periods. For alternative resources to succeed in a full replacement of the net-peak capacity of DCPP, they must provide 2.2 GW of consistent, reliable capacity during net-peak periods. Under the like-for-like analysis and net peak analysis, alternative resources were evaluated based on the ability to replace DCPP. The following are key takeaways of this analysis:

- There are no supply-side or demand-side resources incremental to current procurements that can be built before the planned retirement of DCPP in 2025 because they fail one or more criteria: they are not zero-carbon resources, they compete with existing ordered procurement, they are not technologically mature, or they would be severely limited by the ability to interconnect in a timely manner.
- Demand resources exist in the market but face structural and policy barriers preventing them from scaling up quickly and realizing the full potential.
- By the end of 2025, the Demand Scenario is expected to procure only about 725 MW of incremental net peak capacity (roughly 500 MW of realized potential) out of the 2.2 GW of net-peak capacity provided by DCPP.
- LDES systems with sufficient reliable duration to cover net peak are still being developed and implementing LDES capacity beyond what is already planned in California would require significant effort to make operational in the short term. Thus, LDES options are not available as a replacement to the net-peak capacity of DCPP by the end of 2025.

Table 13: DCPP Resource Replacement Summary

	Like-for-Like Analysis	Net Peak Analysis
Supply Resources	No supply resources can be built by 2025 to cover DCPP's energy production	No supply resources can be built by 2025 to cover capacity of DCPP at net peak
Demand Resources	Demand resources cannot currently provide DCPP energy production by 2025	Only 725 MWs of demand resources could be on-line by 2025
Supply + Demand	No supply + demand resources can be built by 2025 to cover DCPP's energy production by 2025	No additional demand resources can be built by 2025 to cover capacity of DCPP at net peak

Source: Guidehouse analysis for this report

Overall, this analysis shows that by the end of 2025, the 725 MW of incremental resources that can be procured will still lead to a shortfall in both peak power supply and energy generation without increasing GHG emissions. It is possible to do so provided a longer timeline.

APPENDIX A: Acronyms and Abbreviations

ACES	Advanced clean energy storage
BTM	Behind-the-meter
CA	California
CAES	Compressed air energy storage
California ISO	California Independent System Operator
CAPEX	Capital expenditure
CBP	Capacity Bidding Program
CEC	California Energy Commission
CPUC	California Public Utilities Commission
DCPP	Diablo Canyon Power Plant
DER	Distributed energy resource
DOE	Department of Energy
DR	Demand response
DRAM	Demand Response Auction Mechanism
EIA	Energy Information Administration
ELRP	Emergency Load Reduction Program
EUCG	Electric Utility Cost Group
GHG	Greenhouse gas
GRC	General rate case
GW	Gigawatt
GWh	Gigawatt-hour
HVAC	Heating, ventilation, and air conditioning
IRP	Integrated resource plan
LBNL	Lawrence Berkeley National Laboratory
LDES	Long-duration energy storage
LSE	Load-serving entity
MW	Megawatt
MWC	Major work category
NOC	Nuclear operating costs

NRC	Nuclear Regulatory Commission
PG&E	Pacific Gas and Electric
POU	Publicly owned utility
PSH	Pumped storage hydro
RIMS	Resource Interconnection Management System
RPS	Renewables Portfolio Standard
SB	Senate Bill
VPP	Virtual power plant

APPENDIX B: Glossary

Blended gas

Blending of alternative gaseous fuels, such as hydrogen and renewable gas, with fossil gas to operate a system with lower carbon footprint than just operating on fossil gas. Most technologies require modifications or upgrades to properly function with high blends of alternative fuels, where lower blends could potentially be integrated into the system without major modifications.

Combustion turbine

A combustion or gas turbine is a combustion engine installed in a power plant that can convert gaseous fuels to mechanical energy, which in turn drives a generator that produces electrical energy. This conversion is achieved through the localized combustion of the fuel in a combustion system resulting in high-temperature, high pressure-gas stream that spins the blades that make up the turbine that then spins the generator to produce electricity.

Compressed air energy storage (CAES)

Compressed air energy storage is a type of storage that involves compressing air using an electricity-powered compressor into an underground cavern or other storage area. This compressed air is then expanded through a turbine to generate electricity. Usually, fuel is burned before the expansion to increase the quantity of electricity produced and improve the overall efficiency. Similarly, heat losses from compression are sometimes recaptured and supplied to the air before expansion.[40]

Capacity Bidding Program (CBP)

Capacity Bidding Program (CBP) is an aggregator-managed program, a third-party entity acting on behalf of a customer to manage and administer a demand response program, that operates with a day-ahead option and runs May 1 through October 31 but is promoted year-round. There are numerous aggregators participating in CBP.

CAPEX

CAPEX is the contraction of the term capital expenditure, and refers to the expenditures made to acquire, upgrade, and maintain physical assets such as property, plants, buildings, technology, or equipment.[41]

Demand Response Auction Mechanism

The Demand Response Auction Mechanism (DRAM) was created in 2014 under the guidance of the California Public Utility Commission (CPUC) to harmonize utility-based reliability demand response with California ISO, the state's grid operator. The program seeks to allow California

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40 Compressed Air Energy Storage - EPRI Storage Wiki.

41 Capital Expenditure (CAPEX) Definition, Formula, and Examples (investopedia.com).

ISO to add reliable demand response resources to areas of California where electric reliability may be at risk.

Distributed energy resources (DER)

Small-scale power generation technologies (typically in the range of 3 to 10,000 kilowatts) located close to where electricity is used (for example, a home or business) to provide an alternative to or an enhancement of the traditional electric power system.

Demand response (DR)

Demand response refers to providing wholesale and retail electricity customers with the ability to choose to respond to time-based prices and other incentives by reducing or shifting electricity use ("shift DR"). Particularly this occurs during peak-demand periods, so that changes in customer demand become a viable option for addressing pricing, system operations and reliability, infrastructure planning, operation and deferral, and other issues. It has been used traditionally to shed load in extreme events ("shed DR"). It also has the potential to be used as a low-greenhouse gas, low-cost, price-responsive option to help integrate renewable energy and provide grid-stabilizing services, especially when several distributed energy resources are used in combination and opportunities to earn income make the investment worthwhile. For more information, see the CPUC Demand Response Web page.

Electric Utility Cost Group (EUCG)

Electric Utility Cost Group (EUCG) is a nonprofit trade organization that provides a professional working forum for the electric utility industry to share information to help individual companies improve their operating, maintenance, and construction performance. Performance, cost, and process information using standardized formats is shared via workshops and data reports. EUCG web page, https://www.eucg.org/about/learn.cfm.

Electric vehicle control infrastructure

Electric vehicle (EV) control infrastructure are components and technologies in EV charging networks. In the context of this analysis and advanced EV charging, these refer primarily to smart chargers and bidirectional chargers. Smart chargers are EV chargers that respond automatically to price signals and can optimize EV charging loads. Bidirectional chargers are chargers that allow energy to flow two ways into the vehicle and out of the vehicle. Common uses for these types of chargers are commonly referred to as vehicle-to-everything (V2X) and include applications such as vehicle-to-grid (V2G) and vehicle-to-building (V2B). In the context of this analysis and demand response (DR), bidirectional chargers are typically connected to the electrical grid (V2G) to provide support with load reduction and shifting.

Emergency Load-Reduction Program (ELRP)

The ELRP is a five-year pilot program administered by PG&E designed to pay electricity consumers for reducing energy consumption or increasing electricity supply during periods of electrical grid emergencies. The ELRP pilot seeks to offer a new tool for the electric grid operators and utilities for reducing energy consumption during a grid emergency to reduce the risk of electricity outages when the available energy supply is insufficient to satisfy the anticipated electricity demand.

Fuel cells

A device or an electrochemical engine with no moving parts that converts the chemical energy of a fuel, such as hydrogen, and an oxidant, such as oxygen, directly into electricity. The principal components of a fuel cell are catalytically activated electrodes for the fuel (anode) and the oxidant (cathode) and an electrolyte to conduct ions between the two electrodes, thus producing electricity.

Heating, ventilation, and air conditioning (HVAC)

HVAC refers to equipment and systems that regulate and move heated and cooled air throughout residential and commercial buildings. While there are a wide variety of HVAC systems, in principle, they all take air and use a mechanical ventilation system to heat or cool it to a desired temperature.

Integrated Resource Planning (IRP)

The CPUC's Integrated Resource Planning (IRP) process is an "umbrella" planning proceeding to consider all of its electric procurement policies and programs and ensure California has a safe, reliable, and cost-effective electricity supply. The proceeding is also the Commission's primary venue for implementation of the Senate Bill 350 requirements related to IRP (Public Utilities Code Sections 454.51 and 454.52). The process ensures that load serving entities meet targets that allow the electricity sector to contribute to California's economy-wide greenhouse gas emissions reductions goals. For more information see the CPUC Integrated Resource Plan and Long-Term Procurement Plan (IRP-LTPP) Web page.

Long-duration energy storage (LDES)

There is no single definition for LDES in the energy community. For this analysis, long-duration energy storage (LDES) is an energy storage system that is able to provide at least 8 hours of stored energy. There are systems that look to go well beyond 8 hours to provide 100 hours or even seasonal storage capabilities. There are several types of LDES technologies that are currently being explored, including:

- **Electrochemical:** These are the most known storage technologies in the market. These are systems capable of using electrical energy to promote chemical reactions, thus storing electricity as chemical energy, and inversely can convert the stored chemical energy into electric energy, discharging. Common electrochemical technologies include lithium-ion, flow, iron air, zinc, and sodium.
- **Mechanical:** Technologies that are capable of storing energy by applying force to an appropriate medium, such as water and air, to deliver acceleration, compression, or displacement against gravity. This is the storage of kinetic energy or potential energy. This process can be reversed to recover the stored energy. Common systems include pumped storage hydro storage, compressed air energy storage, and flywheels.
- **Thermal:** Technologies that are capable of storing energy by heating a medium. A medium gains energy when its temperature is increased and loses it when it is decreased. Common mediums and materials used for these energy storage systems include solid (for example, sand) and liquid (for example, molten salts).

Load-serving entity (LSE)

A load-serving entity is defined by the California Independent System Operator as an entity that has been "granted authority by state or local law, regulation or franchise to serve [their] own load directly through wholesale energy purchases." For more information, see the California Independent System Operator's Web page.

Publicly owned utility (POU)

Nonprofit utility providers owned by a community and operated by municipalities, counties, states, public power districts, or other public organizations. Within POUs, residents have a say in decisions and policies about rates, services, generating fuels and the environment.

Pumped storage hydropower (PSH)

Pumped storage hydropower (PSH) is a type of hydroelectric energy storage. It is a configuration of two water reservoirs at different elevations that can generate power as water moves down from one to the other (discharge), passing through a turbine. The system also requires power as it pumps water back into the upper reservoir (recharge). PSH acts similarly to a giant battery because it can store power and then release it when needed.[42]

Reciprocating engine

A reciprocating engine is an engine that uses reciprocating pistons to convert high temperature and high pressure into a rotating motion. Reciprocating engines are typically internal combustion engines and can be used for power generation, transportation, and other uses.[43]

Renewable gas

Renewable gas is essentially biogas or biomethane that has been cleaned and conditioned and can be a direct replacement of natural gas. It can be used to generate electricity, heat, and combined electricity and heating for power plants. Biogas can be produced through a biochemical process such as anaerobic digestion, through thermochemical means such as gasification, or from landfills.[44]

Smart thermostat

Wi-Fi thermostat that can be used with home automation and are responsible for controlling a home's heating, ventilation, and air conditioning.

Virtual power plant (VPP)

In the context of this analysis, VPPs are controlled aggregations of zero-carbon distributed energy resources (DERs) and dispatchable demand response (DR) measures optimized to provide clean energy, reliability, and grid services. The following provide two more general definitions of VPPs:

42 https://www.energy.gov/eere/water/pumped-storage-hydropower

43 https://www.energy.gov/eere/amo/articles/reciprocating-engines-doe-chp-technology-fact-sheet-series-fact-sheet-2016

44 https://afdc.energy.gov/fuels/natural_gas_renewable.html

- **Department of Energy:** Virtual power plants, generally considered a connected aggregation of distributed energy resource (DER) technologies, offer deeper integration of renewables and demand flexibility, which in turn offers more Americans cleaner and more affordable power.[45]
- **Brattle Group:** A VPP is a portfolio of actively controlled distributed energy resources (DERs). Operation of the DERs is optimized to provide benefits to the power system, consumers, and the environment.[46]

45 https://www.energy.gov/lpo/virtual-power-plants

46 https://www.brattle.com/wp-content/uploads/2023/04/Real-Reliability-The-Value-of-Virtual-Power_5.3.2023.pdf