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BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company (U39E) for Approval of its Demand Response Programs, Pilots and Budgets for Program Years 2023-2027.	Application 22-05-002
And Related Matters.	Application 22-05-003 Application 22-05-004

ASSIGNED COMMISSIONER'S SCOPING MEMO AND RULING

This Scoping Memo and Ruling (Scoping Memo) sets forth the issues, need for hearing, schedule, category, and other matters necessary to scope this proceeding pursuant to Public Utilities (Pub. Util.) Code Section 1701.1 and Article 7 of the Commission's Rules of Practice and Procedure (Rules).

1. Procedural Background

Demand Response (DR) programs encourage reductions, increases, or shifts in electricity consumption by customers in response to economic or reliability signals. Such programs can provide benefits to ratepayers by reducing the need for construction of new generation and the purchase of high-priced energy, among others. Commission Decision (D.) 17-12-003 directed Pacific Gas and Electric Company (PG&E), San Diego Gas & Electric Company (SDG&E), and Southern California Edison Company (SCE) (collectively, the Utilities) to file by November 1, 2021 their 2023-2027 Demand Response Portfolio Applications. A September 30, 2021 letter issued by the Commission's Executive Director extended the deadline to May 2, 2022.

On May 2, 2022, PG&E (Application (A.) 22-05-002), SDG&E (A.22-05-003), and SCE (A.22-05-004) filed their respective 2023-2027 DR portfolio applications. Pursuant to Rule 7.4, an Administrative Law Judge (ALJ) Ruling issued on May 25, 2022 consolidated these applications (A.22-05-002 et al.,). On June 6, 2022, a Protest to the application was filed by the Public Advocates Office at the California Public Utilities Commission (Cal Advocates), and Responses were filed by the Small Business Utility Advocates, Leapfrog Power, Inc., Google LLC, CPower and Enel X North America, Inc., California Efficiency + Demand Management Council, Polaris Energy Services, Marin Clean Energy, Center for Energy Efficiency and Renewable Technologies, California Energy Storage Alliance, California Large Energy Consumers Association, and the Vehicle Grid Integration Council. Per ALJ Ruling, replies were filed on June 13, 2022 by PG&E, SDG&E, and SCE.

A prehearing conference (PHC) was held on June 16, 2022 to discuss the scope, schedule, and other procedural matters. At the PHC, oral Rule 1.4(a)(3) Motions for Party Status were presented by OhmConnect, Inc., Weave Grid, Inc., and Voltas, Inc. These Motions were granted at the PHC.

2. Clarifying Guidance for the Remainder of This Proceeding

Pursuant to Rule 2.9, the applications seek approval of bridge funding for the 2023 year on an expedited schedule, with a decision to issue by the end of 2022.[1] An expedited schedule is necessary to ensure continued operation of currently ongoing DR programs. The request for an expedited schedule is granted, and the scope and schedule below will reflect this expedited schedule.

[1] PG&E Application, Attachment A; SCE Application, Appendix D X; SDG&E Application, Attachment G.

The proceeding will therefore be phased, with Phase I addressing the Utilities' 2023 Bridge Year Funding Requests. Phase II will address the Utilities' Applications for the years 2024-2027. Although we only expect a decision to be issued with regards to Phase I issues in 2022, it is likely that we will begin considering Phase II issues later in 2022 as well. Additionally, as directed in the previous DR application proceeding,[2] we shall consider the future of the DR Auction Mechanism (Auction Mechanism). On June 24, 2022, the DR Auction Mechanism Evaluation Report submitted by Resource Innovations (formerly known as Nexant) in partnership with Gridwell Consulting (Nexant Team) evaluating the Auction Mechanism from 2018 to 2021 (Nexant Report) was released to the public. With the Nexant Report now issued, we will take party comments on the report and whether to continue the Auction Mechanism for delivery year 2024, also on an expedited schedule.

3. Issues

As discussed above, this proceeding will be addressed in two Phases. Separately, this proceeding will also consider the future of the Auction Mechanism. The issues scoped below are arranged to reflect this division. The Phase I scoped issues are designed to address only the 2023 bridge funding proposals by the Utilities. At a later time, Phase II issues will be scoped addressing the 2024-2027 DR program proposals. Similarly, the Auction Mechanism issues scoped below address only the limited question of whether to approve the Auction Mechanism for 2023 solicitations and 2024 deliveries. The Auction Mechanism's future beyond 2024 will be addressed at a later time, likely along with the other Phase II issues.

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[2] D.19-07-009, at 74.

3.1 Scoping Issues to be Addressed During Phase I, 2023 Bridge Funding

1. Do the applications of PG&E, SCE, and SDG&E requesting approval of DR programs and budgets for Year 2023 advance the goals, principles, and guidance adopted in D.16-09-056 and comply with the directives in D.16-09-056, D.17-12-003, D.21-03-056, and D.21-12-015 as well as other relevant directives listed in prior Commission decisions and rulings?[3]
2. Are the Utilities' proposed 2023 changes to programs and activities, including pilot recommendations and Rule 24 Program Information Technology system enhancements, reasonable and should they be adopted? Similarly, are parties' proposed changes to utilities' programs reasonable?
3. Are the Utilities' requested budgets to implement the proposed programs and cost and rate recovery requests, including continued fund shifting flexibility, reasonable?
4. Are the Utilities proposed programs and portfolios cost-effective pursuant to cost-effectiveness protocols adopted in D.15-11-042 and D.16-06-007? If they are not cost-effective, should they be adopted?
5. Should ratepayers provide $750,000 in 2023 for continued modeling of DR potential and related research overseen by Energy Division?

3.2 Auction Mechanism

1. Should the Utilities be directed to conduct Auction Mechanism solicitations in 2023, for 2024 deliveries, as a continued pilot without further technical refinements, and if so, what budget should be authorized?

[3] Specifically, the applications should comply with directives included, but not limited to those in D.12-04-045, D.14-12-024, D.15-03-042, D.16-06-008, and D.16-06-029, as well as D.16-09-056.

4. Need for Evidentiary Hearing

The Utilities' applications do not request evidentiary hearings for Phase I of this proceeding. At the PHC, parties expressed the possibility of needing evidentiary hearings, but did not request them at this time. PG&E requests time be set aside for potential evidentiary hearings for Phase II. We still expect that there may be factual issues that could be informed by evidentiary hearings, though they may not be required. Accordingly, we leave open the possibility that evidentiary hearing may be needed, and will schedule evidentiary hearings, as necessary or requested, during the course of the proceeding.

5. Schedule

The following revised schedule is adopted here and may be modified by the assigned Commissioner and/or ALJ as required to promote the efficient and fair resolution of the Rulemaking:

Event	Date
Scoping Memo	July 5, 2022
Phase I Opening Testimony Due	July 13, 2022
Phase I Reply Testimony Due	August 3, 2022
Meet and Confer to Determine Need for Evidentiary Hearings	August 8, 2022
Last Day to Request Evidentiary Hearing and Conduct Discovery	August 11, 2022
Evidentiary Hearings	August 15 and 17, 2022
Concurrent Opening Briefs on Phase I	August 22, 2022
Concurrent Reply Briefs on Phase I	September 2, 2022
Proposed Decision	October 2022
Commission decision on Phase I	30 days after issuance of PD

Auction Mechanism Schedule

Event	Date
Scoping Memo	July 5, 2022
Workshop to present results of Nexant Report	July 7, 2022
Supplemental Testimony Due on Nexant Report and Auction Mechanism	August 5, 2022
Reply Testimony Due on Nexant Report and Auction Mechanism	September 2, 2022
Meet and Confer to Determine Need for Evidentiary Hearings	September 9, 2022
Last Day to Request Evidentiary Hearing and Conduct Discovery	September 16, 2022
Evidentiary Hearings	Late September, 2022
Opening Briefs on Nexant Report and Auction Mechanism	October 7, 2022
Concurrent Reply Briefs on Nexant Report and Auction Mechanism	October 28, 2022
Proposed Decision	December 2022

The organization of prepared testimony, comments, and briefs must correlate to the issues identified in this Scoping Memo or other rulings directly seeking specific input from parties to this proceeding.

On July 7, 2022, the Commission's Energy Division will hold a workshop to discuss the Nexant Report. The workshop is a forum for the Nexant Team to present its findings as discussed in the Report and for parties to ask the Nexant Team questions about the Report.

Evidentiary hearings, if needed for Phase I, would take place on August 15 and 17, 2022. Depending on the need for evidentiary hearings, the briefing schedule may be altered for Phase I, in response to comments by multiple parties at the PHC. Under this expedited schedule, the record with regards to Phase I will stand submitted upon the filing of reply comments.

At the PHC, the ALJ discussed a schedule whereby a decision could be rendered so that Auction Mechanism solicitations could be run in 2023 for full 2024 deliveries. Parties expressed concern at the PHC regarding the expedited schedule as the Nexant Report was not yet issued. Given the importance of the Nexant Report to the parties' analysis and the short time frame originally presented at the PHC, the schedule has been changed to allow parties to more fully consider the report and the performance of the Auction Mechanism. Evidentiary hearings, if needed on the scoped Auction Mechanism issues, would take place in late September 2022. If evidentiary hearings are needed, the briefing schedule may be altered.

Based on this schedule, Phase II of the proceeding may not be resolved within 18 months as prescribed by Pub. Util. Code Section 1701. With this Scoping Memo, we extend the statutory deadline for this proceeding to May 2, 2024, to allow time for the successful development and evaluation of the proposed DR portfolios.

6. Requesting Comments from Parties on Nexant Report

As discussed above, the Nexant Team, the consultants hired by the Utilities to conduct the evaluation of the Auction Mechanism for 2018 to 2021, has issued the DR Auction Mechanism Evaluation Report (Nexant Report). The Nexant Report evaluates the Auction Mechanism pilot relative to criteria specified by the Commission and includes a performance assessment of the DR providers participating in the Auction Mechanism pilot for delivery years 2018 to

2021 and an analysis of the solicitation processes for delivery years 2019 to 2021. The public version of the report is attached to this ruling and added to the proceeding record.

The parties are to use the findings and recommendations in the Nexant Report to inform their responses to the issues scoped above related to the Auction Mechanism. Supplemental Testimony on Auction Mechanism issues scoped is due August 5, 2022, and Reply Testimony on September 2, 2022. If the Commission decides to extend the Auction Mechanism through delivery year 2024, additional scoping issues, including any modifications to the Auction Mechanism, may be added in a future ruling.

7. Alternative Dispute Resolution (ADR) Program and Settlements

The Commission's ADR program offers mediation, early neutral evaluation, and facilitation services, and uses ALJs who have been trained as neutrals. At any party's request, the assigned ALJs can refer all or part of this proceeding to the Commission's ADR Coordinator. Additional ADR information is available on the Commission's website.[4]

Any settlement between parties, whether regarding all or some of the issues, shall comply with Article 12 of the Rules and shall be served in writing. Such settlements shall include a complete explanation of the settlement and a complete explanation of why it is reasonable in light of the whole record, consistent with the law and in the public interest. The proposing parties bear the burden of proof as to whether the settlement should be adopted by the Commission.

[4] *See* D.07-05-062, Appendix A, § IV.O.

8. Category of Proceeding and *Ex Parte* Restrictions

The Commission preliminarily determined that this is a ratesetting proceeding.[5] This Scoping Memo confirms the categorization. *Ex parte* communications are permitted, but with restrictions and reporting requirements, pursuant to Article 8 of the Rules.

9. Public Outreach

Pursuant to Pub. Util. Code Section 1711(a), I hereby report that the Commission sought the participation of those likely to be affected by this matter by noticing it in the Commission's monthly newsletter that is served on communities and businesses that subscribe to it and posted on the Commission's website.[6]

In addition, the Commission served the ruling noticing the PHC on the following related service lists:

Proceeding Topic	Proceeding Number
Demand Response	R.13-09-011 and A.17-01-012 et al.
Summer Reliability	R.20-11-003

In the interest of broad notice, this scoping ruling will also be served on the following state and local agencies: California Alternative Energy and Advanced Transportation Financing Authority; the California Energy Commission; and the California Air Resources Board.

[5] Resolution ALJ 176-3508.

[6] Working for California June 2022 Newsletter at page 7.

10. Intervenor Compensation

Pursuant to Pub. Util. Code Section 1804(a)(1), a customer who intends to seek an award of compensation on Phase I issues is required to file and serve a notice of intent to claim compensation by July 16, 2022.

11. Response to Public Comments

Parties may, but are not required to, respond to written comments received from the public. Parties may do so by posting such response using the "Add Public Comment" button on the "Public Comment" tab of the online docket card for the proceeding.

12. Public Advisor

Any person interested in participating in this proceeding who is unfamiliar with the Commission's procedures or has questions about the electronic filing procedures is encouraged to obtain more information at http://consumers.cpuc.ca.gov/pao/ or contact the Commission's Public Advisor at 1-866-849-8390 or 1-866-836-7825 (TTY), or send an e-mail to public.advisor@cpuc.ca.gov.

13. Filing, Service, and Service List

The official service list has been created and is on the Commission's website. Parties should confirm that their information on the service list is correct and serve notice of any errors on the Commission's Process Office, the service list, and the ALJs. Persons may become a party pursuant to Rule 1.4.

When serving any document, each party must ensure that it is using the current official service list on the Commission's website.

This proceeding will follow the electronic service protocol set forth in Rule 1.10. All parties to this proceeding shall serve documents and pleadings using electronic mail, whenever possible, transmitted no later than 5:00 p.m., on the date scheduled for service to occur. Although Rule 1.10 requires service on the ALJ of both an electronic and a paper copy of filed or served documents, parties are directed to only serve ALJs Toy and Jungreis electronically in this proceeding.

When serving documents on Commissioners or their personal advisors, whether or not they are on the official service list, parties must only provide electronic service. Parties must not send hard copies of documents to Commissioners or their personal advisors unless specifically instructed to do so.

Persons who are not parties but wish to receive electronic service of documents filed in the proceeding may contact the Process Office at process_office@cpuc.ca.gov to request addition to the "Information Only" category of the official service list pursuant to Rule 1.9(f).

The Commission encourages those who seek information-only status on the service list to consider the Commission's subscription service as an alternative. The subscription service sends individual notifications to each subscriber of formal e-filings tendered and accepted by the Commission. Notices sent through subscription service are less likely to be flagged by spam or other filters. Notifications can be for a specific proceeding, a range of documents and daily or weekly digests.

14. Receiving Electronic Service from the Commission

Parties and other persons on the service list are advised that it is the responsibility of each person or entity on the service list for Commission proceedings to ensure their ability to receive e-mails from the Commission. Please add "@cpuc.ca.gov" to your e-mail safe sender list and update your e-mail screening practices, settings and filters to ensure receipt of e-mails from the Commission.

15. Assignment of Proceeding

John Reynolds is the assigned Commissioner and Garrett Toy and Jason Jungreis are the assigned ALJs for the proceeding.

IT IS RULED that:

1. The scope of this proceeding as described in Section 3 above is adopted.
2. The schedule of this proceeding is adopted as set forth in Section 5. The statutory deadline is extended to May 2, 2024, and the assigned Commissioner and/or Administrative Law Judges may adjust the schedule of this proceeding, as needed, to promote efficient management of the case.
3. Evidentiary hearing may be needed. For Phase I issues, no later than August 11, 2022, parties may request evidentiary hearing on contested issues, as appropriate. On the limited issue of whether to approve 2024 Auction Mechanism deliveries, parties may request evidentiary hearing no later than September 16, 2022.
4. The category of the proceeding is ratesetting.
5. The attached document, the Demand Response Auction Mechanism Evaluation Report, is added to the proceeding record. Parties are directed to use the document to inform their testimony and comments regarding the Demand Response Auction Mechanism.

This order is effective today.

Dated July 5, 2022, at San Francisco, California.

/s/ JOHN REYNOLDS
John Reynolds
Assigned Commissioner

ATTACHMENT 1

REPORT

Now a part of Resource Innovations

Demand Response Auction Mechanism Evaluation

Submitted by Nexant

in partnership with Gridwell Consulting

[Public Version – Redacted]

May 23, 2022

Prepared by:

Nexant

- Josh Schellenberg, Officer-in-Charge
- George Jiang, Project Manager
- Candice Potter, Task Lead
- Aimee Savage, Task Lead
- Jeremy Smith, Task Lead
- Andrew Hauser, Project Analyst
- Dan Lesperance, Project Analyst
- Anna-Elise Smith, Project Analyst

Gridwell

- Kallie Wells, Task Lead

Contents

1 Executive Summary

In January 2019, the final version of the *Energy Division's Evaluation of Demand Response Auction Mechanism*[1] (DRAM) report was released. The evaluation focused on contracts from 2015 and 2016 (for delivery in 2016 and 2017, respectively) while also considering data from contracts in 2017 for delivery in 2018 and 2019. The report found that DRAM had been successful in engaging new third-party demand response providers (DRPs) and new customers and that the capacity price offers for resource adequacy were generally competitive. However, it also found that bid prices for DRAM resources in the energy wholesale market were generally not competitive as well as inconclusive evidence of their performance and reliability.

Based on the findings of Energy Division's evaluation report, the California Public Utilities Commission (CPUC) approved a continuation of DRAM for four years in Decision 19-07-009 in July 2019, recommending a limited continuation of DRAM to allow for demonstrated improvements in performance and reliability, beginning with a solicitation in 2019. As part of its recommendations, the Commission approved an evaluation program and directed the Investor-Owned Utilities (IOUs) and Energy Division to hire a consultant for evaluation of delivery years 2018 through 2021 and solicitations for 2019 through 2021. Throughout this report, DRAM waves are referred to by their delivery year (e.g., DRAM Wave I is "2016 DRAM"). Since there were two DRAM waves in delivery year 2019, these are distinguished by appending the wave number to the end (e.g., "2019 DRAM (III-B)", "2019 DRAM (IV)", or "2019 DRAM (III-B+IV)"). Table 2-1 shows the delivery year for each DRAM wave.

This report presents the results of this evaluation across the six adopted criteria for success of DRAM, conducted by the Nexant Team.[2] Throughout this report, DRAM waves are referred to by their delivery year (e.g., DRAM Wave I is "2016 DRAM"). Since there were two DRAM waves in delivery year 2019, these are distinguished by appending the wave number to the end (e.g., "2019 DRAM (III-B)", "2019 DRAM (IV)", or "2019 DRAM (III-B+IV)"). Table 2-1 shows the delivery year for each DRAM wave.

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[1] Energy Division's Evaluation of Demand Response Auction Mechanism; California Public Utilities Commission, Energy Division, January, 2019

[2] The Nexant Team is composed of Nexant, Inc. (now Resource Innovations, Inc.) and Gridwell Consulting, Inc.

1.1 Summary of Findings

The DRAM evaluation findings as they apply to each of the evaluation criteria are summarized in Table 1-1 below.

Table 1-1: Summary of DRAM Evaluation Findings

	Evaluation Criteria	Results
1	Did DRAM engage new, viable DRPs?	Yes, two of the nine DRPs that won contracts were new. Viability has improved, but integration challenges remain. The market is moderately to highly concentrated.
2	Did DRAM engage new customers?	Yes, but the proportion of new customers is decreasing in each cycle.
3	Were auction bid prices competitive?	Mostly yes; at the statewide average level, average DRAM contracts are lower than the LRAC and are more competitive with LRAC at the end of this evaluation period (2021 DRAM) than at the beginning (2019 DRAM (IV)). *[REDACTED]*. At the statewide average level, IQR in 2020 was 8% lower than that in 2019 DRAM (IV) and the statewide IQR in 2021 was 21% lower than that of the 2020 DRAM. *[REDACTED]*.
4	Were offer prices competitive in wholesale markets?	No, but they seem to have improved in recent years.
5	Did DRPs meet their contractual obligations?	Mixed; while Must-Offer Obligation (MOO) compliance is high, alignment of Supply Plan Qualifying Capacity and Demonstrated Capacity (DC) with Contracted Capacity is declining year-over-year. Also, only 30% of contracts evaluated fulfilled their 2021 minimum dispatch requirement.
6	Were resources reliable when dispatched?	Mixed; performance is improving but while some DRAM DRPs delivered reliable performance, others did not; accuracy of DRP-estimated delivered energy varies.
RQMD	Should penalties be imposed for delayed customer and meter data that the Utilities provide to DRPs?	Not retroactively, but specific metrics for success and failure of Revenue Quality Meter Data (RQMD) delivery and associated penalties should be established.

1.1.1 Criterion 1 – Did DRAM Engage New, Viable DRPs?

Criterion 1 seeks to evaluate whether DRAM engaged new and viable DRPs to participate in demand response and evaluates the trend in market concentration over the DRAM waves. The previous CPUC DRAM evaluation analyzed the participation of DRPs, market concentration, and their viability in terms of contract terminations and reassignments in 2016 DRAM (I)-2019 DRAM (III-B). This evaluation expands upon that analysis for 2019 DRAM (IV) through 2021 DRAM (VI).

- 2016 DRAM to 2019 DRAM (III-B) engaged sixteen new third-party DRAM providers as DRAM bidders. Ten of these DRPs won contracts during the auctions. From 2019 DRAM (IV) to 2021 DRAM *[REDACTED]* DRPs bid in the DRAM auctions of which five had not previously won a DRAM contract. Nine DRPs won a contract of which two had not previously held a contract in 2016 DRAM to 2019 (III-B) DRAM.

- The 2019 DRAM (IV) to 2021 DRAM procurements became highly concentrated. Only one DRP won residential DRAM contracts during the evaluation period[3]. In the non-residential markets, the three largest DRPs accounted for 94% of the capacity in 2019 DRAM (IV), 75% of the capacity in 2020 DRAM (V), and 88% of the capacity in 2021 DRAM[4]. All three IOU DRAM markets were moderately to highly concentrated in 2019 (IV) to 2021, with SDG&E being the most concentrated.

- While the comparative lack of new market participants and highly concentrated market can be seen as a concerning sign, there has been a significant improvement to the viability of DRPs holding DRAM contracts. From 2019 DRAM (IV) to 2021 DRAM there was only one contract termination and two contract reassignments compared to nine terminations and six reassignments in 2016 DRAM to 2019 DRAM (III-B). This suggests that the DRPs who remain in DRAM are more viable and less likely to terminate a contract before delivering their contracted capacity.

The Nexant Team also conducted interviews with seven DRPs to further understand the underlying challenges related to viability and market concentration. There are four main themes to the integration challenges: unpredictability of the program, lack of support from the IOUs, need for greater flexibility, and administrative burden.

- One of the primary barriers leading to unpredictability is the short-term contracts and variability in prices, which results in DRPs investing less time and resources into each wave than they would if they had a guaranteed multi-year revenue stream. All DRPs

[3] There were two DRPs with residential customers in their portfolio, but only one of those DRPs had contracts that were classified as “residential”.

[4] There were seven non-residential contract holders in 2019 DRAM (IV) and 2020 DRAM. There were six non-residential contract holders in 2021 DRAM.

interviewed agreed that the bidding process needs more transparency, which would obviate the need to undervalue resources in hopes of winning a contract.

- All interviewees expressed concern about receiving inaccurate meter data from the utilities, rarely with enough time to meet deadlines for submitting invoices and quarterly reports. The effort to correct for various data inaccuracies can be substantial, which creates additional delays even after data is received. The DRPs also pointed to the need for better standardization across the IOUs, including data access and formats, customer registration, bidding processes and timelines, and reporting requirements.

- Some DRPs stated that the number of baselines to choose from should be expanded to better represent performance for a wide variety of customer loads and technologies. Further, many hoped the uncapped adjustment that was implemented during the 2020 heat waves will be made permanent, as it more accurately reflects performance for weather-dependent loads.

- All interviewed DRPs discussed the greater amount of operational burden necessary to participate in DRAM compared to IOU demand response programs and resource adequacy (RA) contracts with community choice aggregators (CCAs). While the refinement of rules and processes since the pilot began has appeared to improve DRP viability, it also makes it challenging for new DRPs to join due to the additional time and resources necessary to automate processes or understand procedures. The DRPs believe that the administrative burden scales proportionally with the number of customers in a portfolio, which favors companies specializing in non-residential demand response that aggregate greater capacities from fewer customers.

1.1.2 Criterion 2 – Did DRAM Engage New Customers?

Criterion 2 seeks to evaluate whether DRAM engaged new customers to participate in demand response.

- In the prior DRAM evaluation, it was observed that between 74% and 95% of all customers participating in DRAM in 2016 and 2017 had never participated in an IOU demand response program previously, which was deemed a success. Due to data on individual customer enrollment in 2016 and 2017 being unavailable, the Nexant Team was unable to determine which customers in 2018 DRAM (III-A) had not participated in 2016 and 2017. Therefore, the number of new DRAM customers was not quantified in 2018, but that year did serve as a benchmark for identifying which customers were new to DRAM in 2019 (III-B+IV) and 2020. Compared to 2018 enrollment, about 58% of all participants in 2019 (III-B+IV) were new to DRAM. In 2020, only 26% of enrolled customers had not participated in 2018. Based on these results, DRAM continues to engage new customers to participate in demand response, but that number will likely decrease in the future.

- DRAM continued to engage low-income customers, with 31 to 35% of all participants in 2018 to 2020 enrolled in a California Alternate Rates for Energy (CARE) rate. Participation among Net Energy Metering (NEM) customers rose slightly during the evaluation period, peaking at 13% of all participants in 2020. This evaluation also looked at the number of DRAM customers owning either electric vehicles (EVs) or battery storage. DRAM participation among EV and battery storage owners was around 2% and 1% of total enrollment, respectively. The number of high energy use customers (the highest 5% of their customer class in terms of energy usage) participating in DRAM has increased since the previous evaluation. In 2016, it was found that around 4% of DRAM customers were among the top 5% of energy users, but that rose to around 10% and 8% in PG&E's and SCE's territories, respectively, by 2020. This trend suggests that DRAM is more successfully attracting high energy use customers as intended.

1.1.3 Criterion 3 – Were Auction Bid Prices Competitive?

Criterion 3 asks whether DRAM auction bid prices were competitive, both externally with other capacity resources and internally to each IOU's auction.

- A backdrop for the sets of 2019 DRAM (IV) through 2021 DRAM auction bid and contract prices are the numbers of bidders and sellers and bids entered into each auction. *[REDACTED]*. The number of DRPs winning contracts has increased for PG&E, has shown a net decline at SCE during the three-year period covering the 2019 (IV) through 2021 auctions. SDG&E has not shown net growth or decline during 2019 (IV) through 2021 period. The number of bids received declines between 2019 DRAM (IV) and 2021 DRAM for *[REDACTED]* of the three IOUs, but the number of bids does not necessarily decline year over year during that period. Declining numbers of auction bids may indicate consolidation of market participation.

- Prices for 2019 DRAM (IV) through 2021 DRAM awarded contracts *[REDACTED]*. The average awarded bid *[REDACTED]*. When considering the average of all submitted bids, not just the awarded bids, *[REDACTED]*. At the statewide level, there is no consistent increasing or decreasing year-over-year trend across the 2019 DRAM (IV) through 2021 DRAM auctions – neither statewide average DRAM offers nor awarded bid consistently increased or decreased. There is likewise no consistent trend of improvement in average contract prices to LRAC across the 2019 DRAM (IV) through 2021 DRAM auctions. However, at the statewide average level, average DRAM contracts are more competitive with LRAC at the end of this evaluation period, 2021 DRAM, than at the beginning, 2019 DRAM (IV). Statewide average contract prices are lower than LRAC in all three auctions 2019 DRAM (IV) through 2021 DRAM.

- A comparison of DRAM bid prices to IOU demand response (DR) program capacity payments must be made with the varying program designs in mind. DR program expectations of participants can vary from air conditioning cycling programs that operate with little impact to participants' thermal comfort to interruptible programs that target large C&I customers and incentivize near-complete curtailment of business processes and exact stiff penalties for non-performance. *[REDACTED]*.

- *[REDACTED]*. At the statewide level, the minimum August bid *[REDACTED]* the maximum bid *[REDACTED]*. Considering only the bids between the 25th-75th percentile bids, we find the statewide IQR is decreasing over time: *[REDACTED]* in 2019 DRAM (IV), *[REDACTED]* in 2020, and *[REDACTED]* in 2021, *[REDACTED]*. The statewide IQR in 2020 was 8% lower than that in 2019 DRAM (IV) and the statewide IQR in 2021 was 21% lower than that of the 2020 DRAM.

1.1.4 Criterion 4 – Were Offer Prices Competitive in Wholesale Markets?

Criterion 4 aims to assess whether DRAM bid prices were competitive in the California Independent System Operator (CAISO) wholesale energy market. As noted in the prior DRAM Evaluation, there is a lack of a clear guidance as to what constitutes a competitive offer from DRAM resources. Thus, the Nexant Team evaluated the competitiveness of DRAM resources by analyzing the distribution of bid prices, scheduling rates, and scheduling effectiveness. The analysis shows:

- DRAM resources tend to be offered at prices that far exceed that of both the net benefits test and other resource types. While there appears to be a slight change in bidding more megawatt hours at lower prices than in the past, it is challenging to clearly conclude if this is a trend or a result of the data quality issues.

- Bidding behavior varies widely across DRPs, but most DRPs fall into one of two categories: *[REDACTED].*

- DRAM resources are becoming more effective in getting their capacity scheduled in the day-ahead (DA) and real-time (RT) markets, especially during periods of highest system needs, but remain less active than IOU DR and other resource types.

- DRPs that offer lower bids tend to have higher scheduling rates and scheduling effectiveness.

The Nexant Team concluded that DRAM bid prices, while they remain uncompetitive, appear to be slightly more competitive as we have seen a minor decrease in offer prices in the most recent year in conjunction with upward trends in scheduling rates and scheduling effectiveness. Given that there is minimal expectation with regards to actual dispatch in the market and consistently performing to dispatches, the high offer prices are not necessarily surprising. However, as discussed further in the report, the change in bidding behavior may be in response to the change in contractual obligations starting in 2021; the increase in scheduling rates may also be a result of lower offer prices and tighter supply conditions on the system in general. However, given the data quality issues, it is challenging to clearly conclude if these observations are a result of a change in bidding behavior rather than results impacted primarily by data issues or changes in overall system conditions.

1.1.5 Criterion 5 – Did DRPs Meet Their Contractual Obligations?

Criterion 5 seeks to evaluate if DRPs met their contractual obligations and were able to successfully provide their contracted capacity. This evaluation assessed three types of contract compliance: alignment between contracted capacity, supply plan capacity, and demonstrated capacity; compliance with the must-offer obligation (MOO); and compliance with the minimum energy requirement (effective for 2021 deliveries). The analysis shows:

- In 2018, DRPs[5] were mostly able to demonstrate capacity in close alignment (within about 97%) with the contracted capacity. Demonstrated capacity was mostly based on MOO during this pilot year. DRP compliance was slightly lower from 2019 to 2021, where demonstrated capacity alignment ranged from 79% in 2019 to 65% in 2021.

- MOO compliance was evaluated by comparing total day ahead (DA) market bids to each DRP's MOO for Q3 2020 through Q4 2021. (DRPs were not required to submit quarterly reports, which included DA bids and monthly qualifying capacity values, before 2020 DRAM). At an aggregate level, DRPs were compliant with MOO requirements in all quarters of the evaluation period; DRPs collectively bid at least 100% in every quarter of the evaluation cycle and bid over 100% in every quarter but Q4 2020. When examining results for each individual DRP, MOO compliance varies slightly.

- Finally, this Criterion assessed how well the DRAM contracts met the new minimum dispatch requirement set for DRAM contracts beginning in 2021.[6] Overall, about 30% of the contracts evaluated, representing 23% of the required energy, were in compliance with the new requirement. Most contracts that were not in compliance with the new requirement were held by *[REDACTED]*, with the remaining contracts meeting nearly 90% of the requirement.

1.1.6 Criterion 6 – Were Resources Reliable When Dispatched?

Criterion 6 aims to assess the performance of DRAM resources in the CAISO energy market and evaluates whether the resources are considered reliable when dispatched by the CAISO.

- Overall, DRAM performance appears to be improving year-over-year. However, there is still significant room to increase performance.

- There is also significant variation by DRPs and by dispatch. While some DRPs tend to perform relatively well in a consistent manner, others seem to be performing well during some events and then underperforming significantly for the remainder of their contract term.

[5] Results from 2018 and 2019 do not include *[REDACTED]*.

[6] D.19-12-040 established the new minimum dispatch requirement for DRAM resources starting in 2021.

- There are significant and concerning inconsistencies when calculating performance from different datasets reported by the DRPs, by the Scheduling Coordinators for CAISO settlement purposes, and data calculated by the Nexant Team.

- The accuracy of DRP-reported delivered energy varies greatly by DRP and through time. A majority of data reported by the DRPs overestimate delivered energy, when compared to the Nexant Team's analysis.

- Some DRPs do not report the same delivered energy values in their quarterly reports as they do when the SC reports the delivered energy to CAISO for settlement. These two values should match in principle.

In general, the Nexant Team concluded that performance, while improving in recent years, was sub-par for DRAM resources overall. This may be a factor of the current DRAM design and lack of sufficient penalties for under-performance.

1.1.7 Revenue Quality Meter Data – Should Penalties be Imposed for Delayed Customer and Meter data?

Revenue Quality Meter Data (RQMD) is critical for ensuring a functional monitoring and reporting process, so it is important to have a governance structure that results in timely data delivery. A Working Group (WG) was formed to investigate the causes and impacts of the IOUs providing delayed or missing customer meter data to DRPs so that they may participate in the CAISO wholesale market.

- Due to the lack of an existing framework and agreement establishing a penalty structure, the Nexant Team does not believe penalties should be imposed retroactively on the IOUs for delayed or missing RQMD. However, we believe metrics should be established to define the success or failure of delivery of RQMD that come with penalties or financial earnings depending on if they are met.

- The Team recommends quantifiable revenue loss or fines incurred by the DRPs as a result of delayed or inaccurate RQMD be reviewed and resolved by a neutral third party to determine culpability and potential penalties.

- The Team believes the timeline for revenue loss or penalties to DRPs should be based on the date on which complete and accurate data is delivered, not conclusion of program months.

1.2 Summary of Recommendations

While DRAM has demonstrated some improvements following the 2019 CPUC evaluation and recent changes in DRAM requirements, several fundamental issues have persisted, including:

- Widely varying performance, and consistent underperformance in some cases, have significantly lowered the overall effectiveness of DRAM

- Lack of availability during critical hours, such as the August 2020 heatwave, as studied in more detail in the CAISO Department of Market Monitoring (DMM) report[7]
- Given the above two issues, the additional system capacity (if any) that each DRP has delivered is highly uncertain and varies substantially
- Data errors and reporting inconsistencies, leading to over-compensation and a lack of confidence and transparency regarding the overall performance of DRAM
- Significant administrative burden for all parties involved

To help address these fundamental issues, the Nexant Team provides several recommendations, summarized in Table 1-2. More detail surrounding these recommendations can be found in Section 11.

Table 1-2: Summary of DRAM Recommendations

Issue Area	Recommendation
Performance Incentives	Align incentives of DRAM capacity contracts with demonstrated performance, including consistency and availability, and unique characteristics of DR.
Data Accuracy and Administrative Burden	Develop a centralized data repository and reporting system to increase data accuracy, prevent over-compensation and reduce administrative burden.
Comparing DRAM to other DR Resources	Conduct a cost-effectiveness analysis of DRAM to compare to IOU DR programs and LRAC based on historical performance.
CAISO Market Availability	Further evaluate the impact of minimum load costs, start-up times and market rules on resource availability and market dispatch.
Performance Calculation Methodology	Assess and consider offering other choices in baseline methodology that better represent demand response performance for certain customers.
Revenue Quality Meter Data (RQMD)	Consider establishing specific metrics regarding delivery timeline and data accuracy to define the success or failure of delivery of RQMD with either financial incentives for meeting the requirements or penalties if they are not met. Make RQMD available immediately after validation rather than waiting until the end of the billing cycle.

[7] The CAISO DMM report titled "Demand response issues and performance" found that a major issue for the August 2020 heatwave was that a substantial portion of DR resources, both utility and third-party, was not available to be dispatched in real-time during critical hours. The Nexant Team did not thoroughly investigate this availability issue, given data limitations and the scope of the six criteria for this evaluation, but it is important to consider for these recommendations.

2 Background

In Decision 16-09-056, the California Public Utilities Commission (CPUC) reviewed the consideration of transitioning the Demand Response Auction Mechanism (DRAM) from its pilot status to a fully operational mechanism. The Commission adopted a set of six criteria to determine the success of DRAM: "*a) Were new, viable third-party providers engaged; b) Were new customers engaged; c) Were bid prices competitive; d) Were offer prices competitive in the wholesale markets; e) Did demand response providers aggregate the capacity they contracted, or replace it with demand response from another source in a timely manner; and f) Were resources reliable when dispatched, i.e., did customers perform appropriately.*" In service of evaluating these criteria, the Commission authorized its Energy Division to conduct an analysis of DRAM's first two pilot auctions and the subsequent deliveries.

In January 2019, the final version of the *Energy Division's Evaluation of Demand Response Auction Mechanism*[8] report was released. The evaluation focused on contracts from 2015 and 2016 (for delivery in 2016 and 2017, respectively) while also considering data from contracts in 2017 for delivery in 2018 and 2019. The report found that DRAM had been successful in engaging new third-party demand response providers (DRPs) and new customers. It also found that the capacity price offers for resource adequacy were generally competitive. However, it also found that bid prices for DRAM resources in the energy wholesale market were generally not competitive as well as inconclusive evidence of their performance and reliability.

Based on the findings of Energy Division's evaluation report, the CPUC approved a continuation of DRAM for four years in Decision 19-07-009 in July 2019. The Commission declined to expand DRAM or adopt it as a permanent mechanism without having met all six criteria. Instead, it recommended a limited continuation of DRAM to allow for demonstrated improvements in performance and reliability, beginning with a solicitation in 2019 (DRAM IV). The Energy Division's evaluation report also outlined a two-step approach for improving the Auction Mechanism. Step One included a set of near-term critical improvements, with future and continuous improvements to be part of Step Two. The critical improvements were detailed in the Decision and further refined in D.19-12-040. As part of its recommendations, the Commission approved an evaluation program and directed the Utilities and Energy Division to hire a consultant for evaluation of delivery years 2018 through 2021 and solicitations for 2019 through 2021. This report presents the results of this evaluation across the six adopted criteria for success of DRAM, conducted by the Nexant Team.[9]

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[8] Energy Division's Evaluation of Demand Response Auction Mechanism; California Public Utilities Commission, Energy Division, January, 2019

[9] The Nexant Team is composed of Nexant, Inc. (now Resource Innovations, Inc.) and Gridwell Consulting, Inc.

Table 2-1 summarizes August DRAM capacity and the annual DRAM procurement budget from DRAM I to DRAM VI, totaling nearly $100 million for all waves.

Table 2-1: August Capacity and Annual DRAM Procurement Budget, DRAM I-VI

	DRAM I	DRAM II	DRAM III-A	DRAM III-B	DRAM IV	DRAM V	DRAM VI
Delivery Year	2016	2017	2018	2019	2019	2020*	2021
Capacity Procured (August MW)	40.5	124.6	181.9	205.0	166.6	215.8	206.1
Annual Procurement Budget (Millions USD)	$9.0	$13.5	$13.5	$13.5	$13.5	$12.8	$14.0

* 2020 DRAM had a 7-month delivery period.

3 DRAM Evaluation Objectives

The 2019 Energy Division study focused primarily on DRAM I and II (solicitations in 2015 and 2016 with subsequent deliveries in 2016 and 2017), with some analysis of the DRAM III solicitation activity in 2017 for delivery in 2018 and 2019. Energy Division evaluated DRAM across six criteria as adopted in D.16-09-056. These criteria are also used in this second evaluation of DRAM. The Energy Division study helped identify a number of the Auction Mechanism's shortcomings and highlighted the need for improvements. The Nexant Team, comprised of Nexant (now Resource Innovations) and Gridwell Consulting, developed an evaluation research plan that builds on the 2019 DRAM Evaluation to continue the assessment of the mechanism as specified in D.19-07-009.

3.1 Evaluation Objectives

Table 3-1 presents the specific research questions that each metric component of the evaluation seeks to address. The remainder of the report is organized by these metrics, with each one comprising its own section. The data sources and methodology used to evaluate metrics is presented within each section.

Table 3-1: Evaluation Research Questions by Criterion

Metric	Research Questions
Criterion 1: Did DRAM Engage New, Viable DRPs?	▪ How many new DRPs were engaged each year? ▪ Did the diversity of providers increase? ▪ How many contracts were terminated and/or reassigned each year? ▪ What were the underlying challenges in engaging new, viable DRPs and increasing market concentration?
Criterion 2: Did DRAM Engage New Customers?	▪ What was the customer profile for each DRAM year? ▪ How did demographics of participants change between each successive DRAM auction? ▪ For each customer segment in DRAM III–V, how many participants were new customers or existing DRAM customers?
Criterion 3: Were Auction Bid Prices Competitive?	▪ Were DRAM auction bids less than the long run avoided cost of generation (LRAC)? ▪ Were bids dispersed in a narrow range? ▪ How did bids compare to other appropriate benchmarks (e.g., IOU program capacity payments, CAISO's capacity procurement mechanism soft offer cap, the CAISO's DMM estimated cost for a new gas-fired peaker)?

Metric	Research Questions
Criterion 4: Were Offer Prices Competitive in Wholesale Markets?	▪ What was the dispersion of DRAM energy and ancillary service offer prices in the day-ahead (DA) and real-time (RT) markets relative to (1) other DR resources and (2) other resource types? ▪ Did DRAM resources update bids between the DA and RT markets? ▪ How effective were DRAM resources in getting scheduled in the DA and RT markets? ▪ During the CAISO's 120 highest net load hours how effective were the DRAM resources in getting scheduled in the DA and RT markets?
Criterion 5: Did DRPs Meet Their Contractual Obligations?	▪ What was the alignment of resources based on ratio of Supply Plan capacity (DRP-reported QC) and contract capacity? ▪ What was the alignment of resources based on ratio of invoiced demonstrated capacity and contract capacity? ▪ What was the alignment of resources based on the ratio of bids into the DA market and MOO? ▪ How well did DRPs meet the minimum dispatch requirement for 2021 DRAM contracts to deliver 30 MWh per 1 MW of average QC?
Criterion 6: Were Resources Reliable When Dispatched?	▪ Did DRAM resources deliver energy in accordance with CAISO RT dispatch instructions? ▪ Did DRAM resources awarded ancillary services in the DA market still have the ability to provide the capacity in RT?
Revenue Quality Meter Data Delivery	▪ Based on the RQMD Working Group report, should penalties be imposed for delayed customer and meter data that the Utilities provide to DRPs so that they may participate in the CAISO wholesale market?

4 Criterion 1: Were New, Viable Third-Party Providers Engaged?

The first criterion established in D.16-09-056 was determining whether DRAM engaged new and viable DRPs. This criterion had two key metrics: newness and viability. In the 2019 Energy Division DRAM Evaluation, "new" was defined to be a DRP that had never previously participated as an aggregator in IOU programs. It was graded as pass/fail, where the threshold established for passing was the verification of at least one new third-party DRP bidding into DRAM and winning its bid. The criterion for that evaluation that at least one "new" DRP was involved in DRAM was clearly completed. There were 16 unique new bidders in the 2016 DRAM through 2019 DRAM (III-B) auctions. Ten of these bidders won one or more auction contracts; however, the percentage of new DRPs submitting bids declined in each successive auction. This trend continued into the 2019 DRAM (IV) to 2021 DRAM auctions, with all the DRPs involved having previously served as an aggregator for IOU programs by 2020 DRAM. For the purposes of this evaluation, the definition of "new" was modified to be a DRP that had never previously sold into the DRAM markets.

Viability was defined in the first DRAM evaluation as having companies that bid into the DRAM pilots that were able to deliver the capacity for which they were awarded contracts. In the first two years of the DRAM pilot, only six DRPs completed the full terms of their contracts, three of whom were new entrants. There were significant issues with contract terminations and reassignments. Through in-depth interviews and online surveys, the Energy Division discovered that the majority of the reassigned/terminated DRPs cited unresolved challenges in integrating with the required IOU and CAISO systems, as well as CPUC processes. Additional issues were also identified, with market concentration being a primary concern. Interviewees claimed that the pricing design of DRAM led more experienced, well-capitalized bidders to bid below their delivery costs and drive out competition. Also, the DRAM market leader purchased all reassigned contracts in 2017, which further concentrated the market.

For 2019 DRAM (IV) to 2021 DRAM, the Nexant Team expanded the evaluation scope to also assess the diversification of the DRAM portfolio. By collecting information related to the bidders, quantities, outcomes, and reassignments/terminations from 2016-2019 (III-B) DRAM, the Team was able to assess the subsequent DRAM auctions, determining whether new DRPs are engaged and whether the diversity of providers is improving. Comparing the bid information from previous DRAM auctions gave an initial idea of whether new DRPs were being engaged. Studying the changes in contracted capacity and value across DRAM auctions provides insight into market concentration over time.

To further explore the underlying challenges related to viability and market concentration, the Nexant Team conducted in-depth interviews with DRPs involved in DRAM, including active sellers, recent bidders, and all interested parties that participated in DRAM bidding conferences, seeking to further understand the intricacies in the process of engaging new, viable third-party providers.

The interview topics expanded upon those from the initial online surveys conducted by the Energy Division. These expanded topics included identifying barriers to entry for interested providers; the transparency and equity of the bidding process; factors affecting market concentration; previous knowledge of CAISO markets and requirements; and challenges associated with the auction process, bid submission, contracting, and integration.

4.1 Participation of New Demand Response Providers

From 2019 (IV) to 2021 DRAM, most of the market competitors had previously participated in California DR programs and had won contracts in at least one of the first three DRAM waves. Five of the *[REDACTED]* companies (*[REDACTED]*) submitting bids in these three years had not previously won a DRAM contract. Overall, nine companies won one or more auction contracts during the three years. Of these nine companies winning contracts, two of them (or 17% of winning DRPs) had never previously sold into the DRAM markets. Table 4-1 summarizes these results across the three auctions.

Table 4-1: Summary of DRPs New to DR in California, 2019 (IV)-2021 DRAM[10]

Type of DRP	Count	Percent
Unique Bidders	*[REDACTED]*	100%
Unique Sellers	9	75%
Unique New Sellers	2	17%

Two of these nine sellers won 38 total contracts across all DRAM waves, or 54% of all awards. In contrast, *[REDACTED]* companies bid into the DRAM auctions at least once but never won a contract. The two new sellers were awarded 26 of the 71 total contracts (37%) in 2019 (IV)-2021 DRAM. Figure 4-1 shows the distribution of bidding DRPs winning different numbers of DRAM contracts.

[10] The “unique” designation is intended to eliminate overlap across the IOUs in the statewide total; a “seller” is a third-party bidder that wins a contract.

Figure 4-1: Frequency of DRP Auction Awards, 2019 (IV)-2021 DRAM

RED E D

4.1.1 DRP Participation by IOU

Participation trends varied slightly when considering each IOU's auctions individually in 2019 (IV)-2021 DRAM. *[REDACTED]* companies bid into one or more DRAM auctions conducted in PG&E, with *[REDACTED]* of these not having previously won a DRAM contract. Nine different companies won contracts with PG&E during this period, two of which were new to DRAM. In SCE's territory, *[REDACTED]* companies bid into one or more DRAM auctions, *[REDACTED]* of which had not previously won a DRAM contract. Nine companies won contracts with SCE, two of which were new to DRAM. In SDG&E's territory, only *[REDACTED]* companies bid into one or more DRAM auctions, with *[REDACTED]* having never previously won a DRAM contract. Six different companies won contracts with SDG&E during this period, of which one had not previously participated. Relative to the earlier waves, the number of companies participating in the auctions has decreased, with only *[REDACTED]* unique companies bidding in 2019 (IV)-2021 DRAM compared to *[REDACTED]* companies bidding in 2016-2019 (III-B) DRAM. In addition, most of the contract winners had previously won a DRAM contract, with only two of the nine sellers (17%) having not previously won a DRAM contract.

Table 4-2: Summary of Unique Sellers and Bidders by IOU, 2019 (IV)-2021 DRAM

Type of DRP	PG&E	SCE	SDG&E
Unique Bidders	*[REDACTED]*		
Unique Sellers	9	9	6
Unique New Sellers	2	2	1

In 2016-2019 (III-B) DRAM, almost 70% of the DRAM bidders were new to DR in California. The level of new provider engagement dropped over the successive DRAM waves before reaching

0% in 2019 (IV) DRAM. This trend was most pronounced for SDG&E, with the number of unique bidders participating in SDG&E's auctions declining from a high of *[REDACTED]* in 2017 DRAM to a low of *[REDACTED]* in 2021 DRAM, *[REDACTED]*. This year also saw the lowest level of bidder participation in PG&E and SCE territories, with just *[REDACTED]* and *[REDACTED]* bidding companies, respectively − down from a high of *[REDACTED]* and *[REDACTED]* bidders in 2017 DRAM. Table 4-3 provides a summary of the number of bidders and sellers in all IOU service territories for each DRAM wave.

Table 4-3: Number of Bidders and Sellers by IOU Auction

DRAM Wave	PG&E		SCE		SDG&E	
	Bidders	Sellers	Bidders	Sellers	Bidders	Sellers
2016 (I)	*[REDACTED]*	7	*[REDACTED]*	10	*[REDACTED]*	6
2017 (II)	*[REDACTED]*	6	*[REDACTED]*	7	*[REDACTED]*	6
2018-2019 (III)	*[REDACTED]*	5	*[REDACTED]*	5	*[REDACTED]*	5
2019 (IV)	*[REDACTED]*	4	*[REDACTED]*	6	*[REDACTED]*	3
2020 (V)	*[REDACTED]*	5	*[REDACTED]*	7	*[REDACTED]*	5
2021 (VI)	*[REDACTED]*	5	*[REDACTED]*	4	*[REDACTED]*	3

4.1.2 DRP Participation – Discussion

Earlier DRAM auctions attracted widespread bidding interest among companies new to the IOU DR programs in California. However, the participation of new DRPs dropped with successive DRAM waves, with no new DRPs bidding into the 2021 DRAM market. While the number of DRPs participating decreased, the number of contract terminations and reassignments also dropped. This suggests the remaining sellers proved to be more viable in fulfilling their contracts, which is discussed more in Section 4.3.

4.2 Market Concentration

The Nexant Team summarized auction results and DRAM contracts to measure the relative market concentration of the DRAM program. From 2019 (IV) to 2021, the DRAM program was highly concentrated among large DRPs that held disproportionate shares of the capacity in their respective markets. All residential contracts across all three IOUs in 2019 (IV)-2021 DRAM were held by one DRP, *[REDACTED]*. The non-residential market was slightly less concentrated, but one DRP, *[REDACTED]*, held about 75% of the contracted capacity in all IOUs in 2019 DRAM (IV). In 2020 and 2021, the three largest DRPs accounted for 74% and 88% of the non-residential contracted capacity, respectively[11].

4.2.1 Market Concentration: Overall

A widely-accepted method of measuring market concentration is the Herfindahl–Hirschman Index (HHI)[12]. The HHI can be used to determine market competitiveness and is calculated by

[11] There were seven DRPs with non-residential contracts in 2019 (IV)-2020 DRAM and there were six in 2021 DRAM.

[12] https://www.justice.gov/atr/herfindahl-hirschman-index

squaring the market share of each competing firm and summing the resulting numbers, as shown in the formula below.

Equation 4-1: Herfindahl–Hirschman Index

$$HHI = (s_1 \times 100)^2 + (s_2 \times 100)^2 + (s_3 \times 100)^2 + \cdots + (s_n \times 100)^2$$

Where s_m is the market share (percentage) of firm *m* and *n* is the number of entities competing in the market. The value of the HHI ranges from a high of 10,000 for a complete monopoly (one entity has 100% market share) to a low approaching zero in a "perfectly" competitive market. In general, an HHI value above 2,500 shows the market is highly concentrated (low competitiveness), between 1,500-2,500 is considered moderately concentrated, and below 1,500 indicates low market concentration (high competitiveness). In this section, HHI values are calculated for both total capacity and total contract value.

Table 4-4 shows the total number of sellers and HHI values for 2019 (IV)-2021 DRAM. The overall DRAM market was moderately to highly concentrated in all three years, with 2019 being the least competitive. Even though there were the same number of sellers as 2019, the market became less concentrated in 2020. In 2021, there was one less seller than the previous years and the market was slightly more concentrated.

Table 4-4: Market Concentration Metrics 2019 (IV)-2021 DRAM

Metric	2019 DRAM (IV)	2020 DRAM (V)	2021 DRAM (VI)
Total Sellers	7	7	6
HHI (Capacity)	4,262	2,116	3,077
HHI (Contract Value)	*[REDACTED]*		

An important indicator of market concentration was the percent of total contract capacity and value awarded to each of the twelve sellers across all three IOUs and DRAM auctions. Despite the moderately-sized bidding pool described above, five companies alone captured 90% of the total DRAM contract capacity and 89% of the total contract value across the three auctions before accounting for contract terminations and reassignments (see Table 4-5). Furthermore, the three companies with the largest share controlled 83% of the total DRAM capacity and 82% of the total contract value.

Table 4-5: Market Concentration of Top 5 DRPs Before Contract Terminations and Reassignments, All IOUs 2019 (IV)-2021 DRAM

DRP	Percent Capacity	Percent Contract Value
[REDACTED]	*[REDACTED]*	
[REDACTED]	*[REDACTED]*	
[REDACTED]	*[REDACTED]*	
[REDACTED]	*[REDACTED]*	
[REDACTED]	*[REDACTED]*	
Total	***[REDACTED]***	

Table 4-6 provides the share of capacity and contract value for all selling DRPs by DRAM wave, before contract terminations and reassignments. As shown in the table, the total market became less concentrated after 2019 DRAM (IV), where one DRP controlled over 50% of the capacity and contract value.

Table 4-6: Share of Capacity and Contract Value by DRP, All IOUs

DRP	2019 DRAM (IV)		2020 DRAM (V)		2021 DRAM (VI)	
	Percent MW	Percent Contract Value	Percent MW	Percent Contract Value	Percent MW	Percent Contract Value
CPower	*[REDACTED]*		5%	*[REDACTED]*	5%	*[REDACTED]*
Enel X	*[REDACTED]*		7%	*[REDACTED]*	1%	*[REDACTED]*
Engie	*[REDACTED]*		0%	*[REDACTED]*	0%	*[REDACTED]*
Leap	*[REDACTED]*		35%	*[REDACTED]*	44%	*[REDACTED]*
NRG	*[REDACTED]*		0%	*[REDACTED]*	0%	*[REDACTED]*
OhmConnect	*[REDACTED]*		7%	*[REDACTED]*	14%	*[REDACTED]*
Stem	*[REDACTED]*		9%	*[REDACTED]*	6%	*[REDACTED]*
Tesla	*[REDACTED]*		15%	*[REDACTED]*	0%	*[REDACTED]*
Voltus	*[REDACTED]*		22%	*[REDACTED]*	29%	*[REDACTED]*

Note: The above chart reflects market concentration before contract reassignments.

4.2.2 Market Concentration: Customer Segments

Market concentration accelerated significantly in the residential market, with only one DRP winning residential contracts in 2019 (IV)-2021 DRAM. There was also a large drop in total residential capacity from 504 MW in 2019 DRAM (IV) down to 42 MW in 2020 DRAM and 149 MW in 2021 DRAM. The decrease in 2020 is due in large part to there being no contracted residential capacity in the PG&E territory.

During 2016 DRAM, residential contracts in all IOUs were spread across four companies, with each of these companies winning a minimum of 7% of residential contract value. During 2017 DRAM, the number of companies winning residential contracts increased to five, with each winning at least 8% of the total value of residential contracts that year. However, in 2018 DRAM, just one company won 99% of all residential customer contract value and capacity across the three IOUs. This trend continued into 2019 (IV)-2021 DRAM, where one DRP captured the entire residential[13] DRAM market. The commercial DRAM market was more competitive, but HHI values above 2,000 for all three years indicate the market was still moderately to highly concentrated. Table 4-7 shows the market concentration metrics for 2019 (IV)-2021 DRAM.

Table 4-7: Market Concentration Metrics by Customer Segment 2019 (IV)-2021 DRAM

Customer Segment	Metric	2019 DRAM (IV)	2020 DRAM (V)	2021 DRAM (VI)
Residential	Total Sellers	1	1	1
	HHI (Capacity)	10,000	10,000	10,000
	HHI (Contract Value)	10,000	10,000	10,000
Commercial	Total Sellers	7	7	6
	HHI (Capacity)	5,962	2,216	3,434
	HHI (Contract Value)	*[REDACTED]*		

DRPs encountered numerous challenges with IOU and CAISO systems and data acquisition. These challenges were significantly greater for DRPs aggregating a larger number of customers, which is especially true for the residential market. These challenges became barriers to market entry in the residential segment and likely contributed to the complete concentration of the residential market. Integration challenges are discussed at greater length in Section 4.3.

Table 4-8 displays the non-residential contract values and capacities by DRAM wave and DRP. From 2019 (IV)-2021 DRAM, the non-residential customer segment showed much less concentration than the residential segment, with nine different DRPs participating in at least one wave. Although 2019 DRAM was heavily concentrated *[REDACTED]*, the market became less concentrated in subsequent DRAM waves.

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[13] Residential amounts reflect customer class as described in the contract data. In many cases, contracts were labeled as non-residential but in fact some amount of capacity was filled by residential customers. This creates a conflict in results in Sections 2.1 and 2.2, where we see large residential customer enrollment in contracts that were originally classified as non-residential.

Table 4-8: Non-Residential Contract Value and Capacity Value, by Year, All IOUs

DRP	2019 DRAM (IV)		2020 DRAM (V)		2021 DRAM (VI)	
	Percent MW	Percent Contract Value	Percent MW	Percent Contract Value	Percent MW	Percent Contract Value
CPower	*[REDACTED]*		5%	*[REDACTED]*	6%	*[REDACTED]*
Enel X	*[REDACTED]*		7%	*[REDACTED]*	1%	*[REDACTED]*
Engie	*[REDACTED]*		-	*[REDACTED]*	-	*[REDACTED]*
Leap	*[REDACTED]*		36%	*[REDACTED]*	48%	*[REDACTED]*
NRG	*[REDACTED]*		-	*[REDACTED]*	-	*[REDACTED]*
OhmConnect	*[REDACTED]*		4%	*[REDACTED]*	7%	*[REDACTED]*
Stem	*[REDACTED]*		9%	*[REDACTED]*	6%	*[REDACTED]*
Tesla	*[REDACTED]*		16%	*[REDACTED]*	-	*[REDACTED]*
Voltus	*[REDACTED]*		22%	*[REDACTED]*	32%	*[REDACTED]*

Earlier DRAM waves saw companies with diverse business models, products, or services capturing a significant share of the market. By 2021 DRAM, only one DRP remained where demand response is not their sole focus, Stem, with only a 6% and *[REDACTED]* share of the total capacity and contract value, respectively. Further, two companies participating in 2021, Leap and Voltus, won contracts within five years of their founding. These trends suggest that the market concentration is a result of DRAM becoming a program that is appealing to seasoned aggregators specializing in demand response and is not an attractive opportunity for new companies entering the space. Several DRPs interviewed for this evaluation mentioned administrative burden is a major barrier to entry for new companies, which is described in more detail in Section 4.3.

4.2.3 Market Concentration: IOU Service Territories

Between 2019 (IV)-2021, the DRAM market was highly concentrated in all three IOU territories except for SCE in 2020 and PG&E in 2021, which both classify as moderately concentrated and were years with the highest number of sellers in their respective territories. SDG&E has the least competitive DRAM market, with a maximum of four sellers in 2020. Table 4-9 shows the market concentration metrics by IOU for 2019 (IV)-2021 DRAM.

Table 4-9: Market Concentration Metrics by IOU 2019 (IV)-2021 DRAM

IOU	Metric	2019 DRAM (IV)	2020 DRAM (V)	2021 DRAM (VI)
PG&E	Total Sellers	4	5	6
	HHI (Capacity)	4,667	2,509	2,161
	HHI (Contract Value)		*[REDACTED]*	
SCE	Total Sellers	6	7	4
	HHI (Capacity)	4,551	2,107	4,213
	HHI (Contract Value)		*[REDACTED]*	
SDG&E	Total Sellers	3	4	3
	HHI (Capacity)	7,485	3,673	4,058
	HHI (Contract Value)		*[REDACTED]*	

Figure 4-2 shows the relative market share for each DRP within the three IOU service territories. When examined across the IOUs, DRAM auction results show a high level of concentration. The SDG&E markets were the most concentrated during the 2019 (IV)-2021 DRAM evaluation period, where two sellers controlled about *[REDACTED]* of the contract value in their service area. The SCE and PG&E markets were slightly less concentrated, but still had one seller controlling about *[REDACTED]* of their contract value and two others each representing about *[REDACTED]* of their market.

Figure 4-2: Contract Value by Seller as Percent of Total Across IOUs, 2019 (IV)-2021 DRAM

RED E D

Note: The above chart reflects market concentration before contract reassignments

4.3 DRP Viability

An important indicator of the viability of DRPs participating in DRAM is their ability to deliver the capacity for which they were awarded contracts, meaning the sellers complete contracts without them being terminated or reassigned. The Nexant Team evaluated historical and current contract terminations and reassignments to discuss the viability of DRPs participating in the DRAM program. Table 4-10 shows that seven of nine (78%) unique sellers that were awarded contracts in 2019 (IV)-2021 DRAM completed the full terms of their contracts. This is a slightly higher rate of contract completion compared to 2016-2017, when only six of nine (67%) sellers completed all their contracts.

Table 4-10: Impact of Contract Terminations/Reassignments, 2019 (IV)-2021

Participant Type	DRP Count			
	2019 DRAM (IV)	2020 DRAM (V)	2021 DRAM (VI)	Total
Unique Bidders	*[REDACTED]*			
Unique New Sellers	1	1	0	2
Unique Sellers	7	7	6	9
Unique Sellers Completing All Contracts	5	6[14]	5	7
Unique New Sellers Completing All Contracts	*[REDACTED]*			

Note: The “Total” column reflects the number of unique bidders and sellers across all three DRAM waves, not the sum of each wave.

4.3.1 Contract Terminations and Reassignments

Overall, the number of contract terminations and reassignments decreased between the 2016-2019 (III-B) DRAM and 2019 (IV)-2021 DRAM evaluation periods. In 2019 DRAM (IV) out of seven total sellers, only one DRP terminated a contract and one DRP reassigned a contract. No DRPs terminated or reassigned any contracts in 2020 DRAM. In 2021 DRAM, there were no DRPs with contract terminations and one DRP with contract reassignments[15]. Table 4-11 presents the number of DRPs with terminated or reassigned DRAM contracts for each IOU for 2016-2021 DRAM.

[14] *[REDACTED]*.

[15] *[REDACTED]*.

Table 4-11: Number of DRPs Terminating/Reassigning Contracts by IOU

DRAM Wave	Contract Result	PG&E	SCE	SDG&E	Total
2016 (I)	Termination	1	1	2	**3**
	Reassignment	0	0	0	**0**
2017 (II)	Termination	1	1	0	**1**
	Reassignment	3	2	0	**3**
2018-2019 (III)	Termination	1	2	0	**3**
	Reassignment	1	0	0	**1**
2019 (IV)	Termination	0	1	0	**1**
	Reassignment	1	0	0	**1**
2020 (V)	Termination	0	0	0	**0**
	Reassignment	0	0	0	**0**
2021 (VI)	Termination	0	0	0	**0**
	Reassignment	0	1	0	**1**

Note: The "Total" column reflects the number of unique sellers terminating or reassigning contracts in each DRAM wave across all IOUs, not the sum of each IOU column.

Table 4-12 displays the number of sellers in each IOU territory before and after contract terminations and reassignments. In 2016-2018 DRAM, it was more common for DRPs to terminate contracts and cease DRAM participation before the conclusion of their contract. During the 2019 (IV)-2021 DRAM evaluation period, there was only one contract termination which occurred in SCE. It is notable that there were no contract terminations in 2020 or 2021 and the only reassignments in 2021 *[REDACTED]*.

Table 4-12: Number of Sellers by IOU, Before and After Contract Terminations and Reassignments

DRAM Wave	PG&E		SCE		SDG&E	
	Before	After	Before	After	Before	After
2016 (I)	7	6	10	9	6	4
2017 (II)	6	3	7	4	6	6
2018-2019 (III)	5	4	5	3	5	5
2019 (IV)	4	4	6	5	3	3
2020 (V)	5	5	7	7	5	5
2021 (VI)	5	5	4	4	3	3

Table 4-13 displays the market share of the three largest DRPs by capacity before and after contract terminations and reassignments from 2019 (IV)-2021 DRAM. Note that there were no contract terminations or reassignments in 2020 and two reassignments in 2021.

From 2016-2018 DRAM, the high number of contract terminations and reassignments contributed to increased market concentration as smaller DRPs were running into viability problems and the larger DRPs gained a larger share of the market. *[REDACTED]*.

Table 4-13: Share of Total Capacity Held by the Top Three DRPs, Before and After Contract Terminations and Reassignments

DRP	2019 DRAM (IV)		2020 DRAM (V)		2021 DRAM (VI)	
	Before	After	Before	After	Before	After
Leap	*[REDACTED]*		35%	*[REDACTED]*	44%	*[REDACTED]*
Voltus	*[REDACTED]*		22%	*[REDACTED]*	29%	*[REDACTED]*
OhmConnect[16]	*[REDACTED]*		7%	*[REDACTED]*	14%	*[REDACTED]*
Total (Top 3)	***[REDACTED]***		**64%**	***[REDACTED]***	**88%**	***[REDACTED]***

In terms of number of providers, the number of sellers under contract ranged from a high of seven in 2019 DRAM (IV) in the SCE service territory to a low of three in 2021 DRAM in the SDG&E service territory. Some markets have become more concentrated, with the top three DRPs controlling over 80% of the capacity in 2019 DRAM (IV) and 2021 DRAM. The concentration is most pronounced in the residential DRAM markets where only one DRP controls the entire market in 2019 (IV)-2021 DRAM.

In summary, this analysis indicated that the 2019 (IV)-2021 DRAM pilots were mostly comprised of DRPs with experience either in other California DR programs or past DRAM participation. Although these DRAM waves did not engage as many new DRPs as the first three waves, the DRPs were much more viable as there were no contract terminations or reassignments in 2020 or 2021.

4.3.1.1 Contract Terminations and Reassignments by DRP

Table 4-14 records the contracted capacities, contract terminations, and contract reassignments for each DRP from 2019 (IV)-2021 DRAM. There was one contract termination in 2019 DRAM (IV), *[REDACTED]*. In 2019 DRAM (IV), there was also one contract reassignment, *[REDACTED]*. Neither of these changes affected market concentration in 2019 DRAM (IV), *[REDACTED]*. There were no contract terminations or reassignments in 2020 DRAM. *[REDACTED]*. This is a positive indicator that DRPs participating in DRAM have become much more viable than in the early waves.

16 *[REDACTED]*.

Table 4-14: Contract Amounts, Terminations, and Reassignments by DRP, DRAM Wave, and Customer Class

DRAM Wave	Customer Class	DRP	Contracted MW	Share of Customer Class Capacity	MW after Terminations and Reassignments	Share of Capacity after Terminations and Reassignments
2019 DRAM (IV)	Non-Residential	Leap	*[REDACTED]*		*[REDACTED]*	
		OhmConnect	*[REDACTED]*		*[REDACTED]*	
		Enel X	*[REDACTED]*		*[REDACTED]*	
		Stem	*[REDACTED]*		*[REDACTED]*	
		NRG	*[REDACTED]*		*[REDACTED]*	
		CPower	*[REDACTED]*		*[REDACTED]*	
		Engie	*[REDACTED]*		*[REDACTED]*	
	Residential	OhmConnect	*[REDACTED]*		*[REDACTED]*	
2020 DRAM	Non-Residential	Leap	476	36%	*[REDACTED]*	
		Voltus	294	22%	*[REDACTED]*	
		Tesla	207	16%	*[REDACTED]*	
		Stem	119	9%	*[REDACTED]*	
		Enel X	98	7%	*[REDACTED]*	
		CPower	71	5%	*[REDACTED]*	
		OhmConnect	58	4%	*[REDACTED]*	
	Residential	OhmConnect	42	100%	*[REDACTED]*	
2021 DRAM	Non-Residential	Leap	840	48%	*[REDACTED]*	
		Voltus	554	32%	*[REDACTED]*	
		OhmConnect	120	7%	*[REDACTED]*	
		CPower	101	6%	*[REDACTED]*	
		Stem	114	6%	*[REDACTED]*	
		Enel X	21	1%	*[REDACTED]*	
	Residential	OhmConnect	149	100%	*[REDACTED]*	

In summary, this analysis indicated that although the 2019 (IV)-2021 DRAM pilots engaged fewer DRPs than in 2016-2018, the DRPs were much more viable, *[REDACTED]*.

4.4 Challenges Faced by Providers

To further understand the underlying challenges related to viability and market concentration, the Nexant Team conducted in-depth interviews with DRPs that were sorted into three different levels of DRAM involvement:

- DRPs with at least one contract award in 2019 (IV)-2021 DRAM (sellers),

- DRPs that bid into at least one auction in 2019 (IV)-2021 DRAM but were not awarded a contract (recent bidders)
- DRPs that had previously sold in 2016-2018 DRAM or attended a recent DRAM Bidders' Conference but chose not to bid (did not bid)

The Nexant Team attempted to contact a total of nine DRPs with contract awards in 2019 (IV)-2021 DRAM but were only able to interview five sellers. A sixth seller provided responses to our interview questions via email. The Team also reached out to two DRPs that bid in at least one auction across 2019 (IV)-2021 DRAM, but only one completed an interview. There were challenges recruiting the companies that attended the Bidders' Conferences, including the lack of attendance data for the 2021 conference and that many of the representatives who attended older conferences were no longer employed by the companies. We identified nearly twenty companies that had attended a Bidders' Conference in the last three years but were unable to complete an interview with any of these companies.

These three distinct survey groups provide different perspectives to better understand the intricacies in the process of engaging new, viable DRPs. Our interviews covered a wide range of topics related to DRAM, depending on the level of DRP involvement, including:

- The transparency and equity of the capacity solicitation and bidding process,
- Factors affecting market concentration,
- IOU systems integration challenges, including customer enrollment, meter data management, and customer registration,
- CAISO systems integration challenges, including registration issues, market rules, and settlement processes,
- Commission processes and rules,
- Contract terminations and reassignments, and
- Any other challenges or barriers experienced by the DRPs.

The following sections summarize findings for each topic area based on feedback collected during the DRP interviews.

4.4.1 Business Characteristics and Program Participation

The first portion of the interview focused on company background information, including whether the DRP participates as an aggregator in other demand response programs and their preference among the available procurement mechanisms. The Nexant Team also asked DRPs to share what they think are the primary barriers to participation in DRAM.

Five of the seven DRPs interviewed are solely demand response providers, while the remaining two have business models focused on other energy products, such as energy storage. All the aggregators participate in other energy markets, ranging from the various wholesale markets in the United States to other markets located internationally. Three of the seven DRPs provide demand response services to both residential and non-residential customers, whereas the remaining four focus solely on one customer segment.

Only one of the aggregators said that DRAM is their preferred procurement mechanism over IOU programs like the Capacity Bidding Program (CBP) or Community Choice Aggregation (CCA) Resource Adequacy (RA). The other six DRPs all preferred CCA RA contracts for two key reasons: first, they allow for longer contract terms, which provides more predictable revenue at fixed prices; and second, CCA contracts have less administrative burden and testing requirements compared to DRAM. Five of the seven DRPs, *[REDACTED]*, said they still plan on bidding in the future if the program is extended.

There were three primary barriers to participating in DRAM that were raised by all seven of the DRPs interviewed:

- The administrative burden, which has increased over time as rules have become more stringent compared to other programs,
- The lack of timely and accurate meter data from the IOUs to meet invoicing and quarterly reporting timelines, and
- The short-term contracts, which do not provide a guaranteed and reliable revenue stream to customers like other programs and makes investments to grow the business riskier.

One DRP mentioned that the administrative burden scales proportionally with the number of customers in a portfolio, which favors companies that aggregate greater capacities from fewer customers.

Other barriers raised during the interviews include:

- The steady decrease in capacity prices and the increase in number of hours required to dispatch becoming less of an advantage over utility programs,
- The longer nomination timeframe not allowing for as accurate of forecasting or planning,
- The requirement to test resources for 6 of 12 months,
- The 30 MWh per MW of average Qualifying Capacity dispatch requirement,
- The process and delays to unenroll customers from utility programs before they are eligible to participate in DRAM,

- Not being able to move customers from one resource to another,
- The lack of standardization in various processes across the three IOUs,
- That the CCAs tend to be more collaborative, and
- That net exports are not counted towards demand response performance.

Many of these barriers are discussed in greater detail in the following sections.

4.4.2 Capacity Solicitation and Bidding Process

In the next section of the interview, the Team asked DRPs to describe their experience and satisfaction with the DRAM capacity bidding process, including whether they thought the process was fair and transparent. We also asked for thoughts on why the number of DRPs participating has decreased since the pilot began.

All seven DRPs said they feel the bidding process is straightforward, but opinions varied on whether the process is fair and transparent. Five of the seven DRPs said the bidding process is not fair due to a lack of transparency, citing a lack of feedback on bids and whether cheaper, less reliable bids are selected over more tenured, but more expensive providers. Two said it was fair because rules are clear ahead of time and the process is reviewed by an independent evaluator, but still agreed that the process needs more transparency. One DRP said the process is a “black box” where more transparency would produce more realistic bids and reliable resources, rather than awarding contracts to the cheaper resources. This lack of visibility into the how contracts are awarded causes some DRPs to undervalue their capacity just in hopes of winning a contract. This also prevents DRPs from understanding why their bid might not be accepted and correct for it in the future. Some DRPs originally saw the program as a potential incubator for new technologies, like behind-the-meter (BTM) distributed energy resources (DERs), to provide load into the market. However, some of the hurdles put in place to improve viability and push out lower performing providers, such as the qualifying capacity methodology being built around averages rather than from the bottom up, the complicated timing of solicitations, and the limited number of megawatts and budget for the program, have made it more challenging for new players to participate and has led to further concentration of the market. Several DRPs also mentioned how it is challenging to provide accurate bids more than a year in advance of the delivery window.

Some suggestions provided to improve the bidding process include more uniformity between the IOUs in terms of timelines and bidding templates, as well as more transparency on what constitutes a viable bid versus an unviable one. One interviewee suggested that since cost effectiveness models are typically publicly available for energy efficiency or demand response programs, they should be available for DRAM. The primary reasons provided for why the number of DRPs participating in the process has declined over time are the same primary barriers mentioned in the previous section: including the operational overhead to participate, the need to bid so far in advance of the delivery, uncertainty about the program’s renewal, and the various rules put in place to ensure viability that drive them to IOU programs or opportunities with non-IOU load serving entities (LSEs). One DRP mentioned that if prices in CBP continue to rise and other IOUs provide an elect option like PG&E's program offers, which allows aggregators to select their own CAISO market bid price within specified operation hours, it would be more difficult to justify participating in DRAM due to the additional effort required.

4.4.3 IOU Systems Integration Challenges

4.4.3.1 Customer Enrollment

The DRPs were asked to provide their overall experience with the utility processes to enroll customers into DRAM, as well as provide examples of any challenges they've experienced. Three of the seven companies interviewed said that customer enrollment is handled by a scheduling coordinator, which limits their view of the entire process. The primary challenge raised by six of the seven companies interviewed is inaccurate customer data causing delays in the enrollment process, which in some cases delays customers from being able to participate in the market for as long as a few months. Some examples of data issues included mislabeled account IDs and incorrect enrollment status in other programs that makes a customer ineligible to participate in DRAM. Another issue mentioned was that customer segment information has been incorrect (labeling residential customers as non-residential), which in one case that was caught by the DRP would have required residential customers to sign backup generator attestation forms and possibly discourage many of those customers from enrolling. One DRP mentioned that there should be a process that alerts aggregators whenever a customer's information changes that would make them ineligible to participate unless it is remedied.

Overall, most DRPs are satisfied with the customer enrollment process and said the Click-Thru Customer Information Service Request – Demand Response Provider (CISR-DRP) forms have brought substantial improvements since the pilot began. This is a significant improvement over feedback received during the last evaluation, when 88% of DRPs interviewed said customer fatigue with the paper CISR forms causing loss of customer enrollment was the primary barrier. One DRP said that California's data sharing authorization process is still much better compared to other states but would benefit from allowing a customer to give agency to a third-party when new equipment like battery storage or EV chargers are installed so engagement with the customer is not lost over time. Two DRPs said there are a lot of behind-the-meter resources that are underutilized for demand response because it is difficult to reengage residential customers. One DRP mentioned that new frictionless or automated enrollment is needed to unlock the full potential of the residential customer segment, noting the process has mostly only helped with C&I customers.

There are other challenges with the Click-Thru CISR that required reverting to the use of the paper forms, including not being able to name a secondary DRP on the form, which would allow both the scheduling coordinator and contracted DRP to receive metered data for their own analysis. A few DRPs mentioned that utility systems were sometimes down (especially SCE's) for days or even weeks, which required reverting to paper forms. In one specific example, a DRP referenced a utility data systems outage that prevented customers from authorizing access to their data for two weeks, impacting their ability to successfully recruit customers into the program.

While not all the DRPs have experience with IOU programs, those that do said the process to enroll customers into DRAM seems slower overall and has more problems compared to enrolling customers into utility programs such as CBP or Base Interruptible Program (BIP), with some interviewees noting more support and collaboration from the IOUs when enrolling customers into their own programs.

4.4.3.2 Meter Data Management

All seven of the interviewees reported recurring problems obtaining timely and accurate meter data from the IOUs, with six of them saying it was either the most or second-most significant barrier to participating in the program. All three IOUs had data delivery and accuracy challenges, but SCE was identified by the DRPs as the IOU with the most regular issues delivering timely and accurate meter data. Most DRPs reported significant delays receiving meter data from the IOUs, which sometimes led to delayed payments or penalties. One DRP said that while quarterly reports are due within 30 days of a trade date, meter data is rarely received within 30 days or sometimes even 60 days. Another DRP said they have incurred penalties for delayed quarterly reports due solely to the lack of timely, accurate data. Another DRP mentioned the delays caused them to incur significant fines due to CAISO charging a $1,000 per trade date penalty for resettlements if it occurs after the 52-business day settlement deadline. A few DRPs mentioned the SCE billing system overhaul created additional challenges, including even longer delays than usual. Data delays also lower customer satisfaction while they wait to see their performance and don't receive actionable information that would allow them to adjust controls or correct problems to improve performance. One recent, beneficial change that helps remedy the issue of delayed data is that DRPs are now allowed to submit a new invoice within a certain time period if they receive updated meter data from the IOU.

The DRPs also provided several examples of inaccurate data that created additional challenges submitting invoices and quarterly reports. DRPs reported receiving meter data for the wrong meters or accounts, data that has been shifted forward or backward an hour or more, data that is missing, or the granularity of data is suspect (load remains perfectly flat for extended periods, shifting up or down every few hours). Many of these data quality issues have led to misrepresentation of customer performance and forfeiture of revenue. One DRP said that without knowing if DRAM is going to be renewed, it's difficult to commit the additional time and resources to building quality control automation to improve data handling procedures. Two DRPs mentioned standardization in data format across the IOUs would greatly improve the process. Another DRP elected to include only two customers in their 2022 DRAM portfolio specifically to avoid extensive data issues and burden.

Three of the seven DRPs said that the lack of financial incentive or penalty for the utilities to meet the data quality standard or timeline is a significant problem. One DRP suggested that metrics should be established that define success or failure criteria for delivery of Revenue

Quality Meter Data (RQMD) that come with penalties if they are not met. An alternative suggestion was to provide utilities with a financial earnings opportunity if the metrics are met, which would help motivate utilities to prioritize data fulfillment as they would for their own programs. DRPs feel they should not incur resettlement penalties resulting from lack of timely and accurate data from the utilities. These should be enforced on the utilities if they are solely responsible for data issues. These topics are covered in more detail in Section 9.6.

The final topic discussed with the DRPs regarding meter data management was whether CAISO's Meter Generator Output (MGO) protocol would be an improvement over using traditional meter data. Three of the interviewees said having the option to use MGO to calculate performance would be a significant improvement and provide more accurate results for technologies like battery storage or electric vehicle charging. One DRP said they avoid enrolling battery storage devices located at high energy usage facilities because variations in customer load can completely mask the battery's performance, which use of MGO would resolve. Another DRP was still skeptical, saying that while MGO is critical for certain resources, it's still of little value until net exports can be counted towards performance.

4.4.3.3 Customer Registration

CAISO systems require IOU confirmation of DRP customer registrations, which caused additional delays for some DRPs. One DRP mentioned that dual registration issues occurring when a customer is already enrolled in another program or is on an ineligible tariff cause significant delays in registration. The process to resolve these challenges is made more difficult by the lack of a central repository to track issues like the validation lists with the utility programs. Each time registration is resubmitted, there is a 10-day waiting period. If multiple issues occur during the registration process, it can easily lead to a month or more delay before getting that resource into the market.

DRPs also faced challenges when unenrolling customers from IOU DR programs to become eligible to participate in DRAM. One DRP mentioned there should be a smoother process to unenroll customers from utility programs, possibly automatically unenrolling the customer from the IOU program when they register in DRAM. There were cases when customers had to contact the utility directly to unenroll from a program to become eligible to participate in DRAM, which delays participation and could potentially deter the customer from joining.

4.4.4 CAISO Systems Integration Challenges

4.4.4.1 Registration Issues

In the next section of the interview, the Team asked DRPs to describe their experience registering resources with CAISO and any existing challenges. They were also asked if the process of adding or removing customers from a resource has improved over time.

As previously mentioned, there are still challenges getting customers de-registered from a utility program and registered into DRAM, which can cause delays depending on whether the resource is in a sub-LAP that was already set up, or if a new one is being created. One DRP explained that DRAM is "one of the only markets where there's not a defined timeline between starting to enroll a customer and having them market ready – and that becomes a little challenging. It's part of why the timelines are longer in DRAM." Another issue raised is that the P_{max} and P_{min} (maximum and minimum capacity of a resource, respectively) construct of registering resources with CAISO is ineffective for dynamic resources. This DRP said that they have shared their concern with CAISO that the registration process, including the master file setup and parameters, do not make sense for DR resources. One DRP said the website used to confirm registration is slow and requires a lot of manual entry. They are working on internal processes to automate the process, but the registration system API is lacking proper documentation.

A few DRPs said the process of moving resource IDs has improved over time, referencing the ability to add an account to a resource without pulling the whole account out of the market. They also appreciated the removal of the single LSE per resource restriction, as it means there are less resources to manage and eliminates the need to establish a new CAISO resource for the customer, which would otherwise trigger a 10-business day waiting period for approval. Most DRPs said the process to register resources with CAISO has improved over time and ranks low in the list of challenges with DRAM.

4.4.4.2 Market Rules

There were a few market rules that have posed challenges to the DRPs. Two of the interviewees mentioned the discrepancy between the number of hours they are required to bid versus the number of hours they are required to perform. One of those DRPs manages battery storage devices and said that issue has been particularly challenging for them. They said that during the 2020 heatwaves there were times where prices were so high that their resources would get dispatched for five hours, even though they had tried to set a price high enough to avoid getting dispatched for the fifth hour. They would prefer alignment between the rules and be able to provide a realistic bid curve rather than inflating it to avoid being dispatched for more hours than they can provide.

One DRP said that having to match Pmax and Net Qualifying Capacity (NQC) between the master file and PUC list is a problem because they can't be lowered over the course of the year. This results in them doing everything one month at a time and firming the portfolio much earlier than they would otherwise, leading to less accurate and often more conservative estimates that undervalue the resources. Another market rule challenge mentioned during the interviews is that the testing requirement for six months of the year means seasonal loads (like agricultural pumping or space cooling) are not representative during cooler months. Finally, one DRP said that because current market rules are so complicated, they present a barrier for new companies trying to enter the market.

A market rule barrier that is significantly challenging for companies controlling battery storage is that net exports are not counted as demand response performance. This limits the number of customers that are willing to participate, especially those that pair solar and battery storage, because net exports often occur in the early evening during typical dispatch hours and they can't get credit. In fact, one DRP has chosen not to participate in DRAM until this rule is changed, noting that the Emergency Load Reduction Program (ELRP) has the potential to solve this constraint.

Some issues with CAISO market design caused particular challenges during the 2020 heatwave events. One DRP said they went above and beyond what was required to dispatch customers as frequently as possible and support the grid. If a customer isn't dispatched in the day-ahead market, they aren't necessarily required to bid in the real-time market. In some cases, there were customers that bid at economic prices but weren't getting dispatched even when the market was above $1,000. This DRP dispatched those customers anyway and paid out of pocket hoping that CAISO and CPUC would recognize the effort and compensate for it. There were also weekend emergency events that occurred but were not eligible for compensation under the DRAM rules. According to the DRPs, not paying customers for participating when the grid needs it most is going to stifle growth and discourage customers from participating in demand response.

4.4.4.3 Settlement Processes

Several interviewees pointed out challenges with current CAISO settlement processes. Five of the seven DRPs said one of the biggest challenges is that the timeline CAISO requires for settlement does not account for the recurring issues obtaining timely, accurate meter data from the IOUs.

Most DRPs spoke about how the current 10-of-10 baseline methodology does not accurately represent performance and they should be allowed to select from other CAISO approved baseline approaches for certain customers, especially those with irregular or highly weather-dependent load patterns or those that operate only four days a week. One DRP suggested a "drop-to" firm service level baseline or other "X-of-Y" baselines other than 10-of-10, like those seen in other markets across the country, that would allow for load irregularities more common with large commercial or industrial customers. Four of the interviewees said the 20% adjustment cap has been a challenge to reflect performance of weather-dependent loads and would prefer an uncapped adjustment to the baseline, as was allowed during the 2020 heat wave. Three DRPs again mentioned the use of MGO would be much preferred for estimating performance for battery storage devices, electric vehicle charging, or other loads that are sub-metered.

Two DRPs spoke about the limitations of capping performance at each individual resource ID. Both said it is common for one resource to overperform and another underperform, so it would be beneficial if these were allowed to balance each other out.

Another interviewee indicated that the CAISO website for validating performance reports is slow and not user friendly, requiring a significant amount of time to use for portfolios with a high number of customers.

Finally, two other DRPs talked about how tariff rules are well documented but are still challenging to understand and require significant resources to get up to speed. One DRP mentioned the complexity of tariff rules is a significant barrier to entry for new aggregators, particularly those that cannot afford to rely on a scheduling coordinator.

4.4.5 Commission Rules and Processes

A few of the Commission rules or processes posed challenges to the DRPs. One DRP said the delivered energy requirement, which requires resources be dispatched for at least 30 MWh per MW of qualifying capacity per season, is a nuisance compared to just having the load on standby to align with heat waves and flex alerts and delivering 30 hours if the pricing clears. Another DRP commented on the same requirement, saying the delivered energy requirement is disconnected from grid need, customer capability, and is made even more difficult by the delays in receiving meter data. They said that by October, they have no way of knowing if they have met the 30 MWh per MW energy requirement because they haven't received summer meter data to track their progress. As a result, they adjust market bids to prices lower than they wanted just to ensure they cover the 30 MWh per MW requirement, which results in a $10,000 per MW penalty if it is not met.

Three DRPs mentioned that the timeline for the quarterly reports seems reasonable but is unrealistic due to how often meter data is late. Another DRP said they would like more clarification from the CPUC in terms of reporting expectations, particularly when they are participating in both the DA and RT markets. They mentioned there was a lot of back and forth to determine what was needed, which if resolved earlier on, could have prevented a lot of operational burden. Another DRP mentioned that when DRAM V lapsed from January to May 2020, it put a significant damper on the market.

4.4.6 Steps to Ensure DRP Viability

The Nexant Team asked the DRPs to make recommendations on steps to ensure DRPs can aggregate the capacity they bid and deliver the capacity they are contracted for. Most of the interviewees agreed that many steps have been taken since the pilot began to ensure DRP viability, which has resulted in lower frequency of contract terminations and reassignments. However, these same DRPs also said that the steps make it difficult for newer companies to enter the market, leading to further market concentration. One DRP said that without a proven track record it's difficult to set up new procedures to ensure viability of new players without discouraging them from trying. They suggested that perhaps there should be preferential treatment given to those providers with good track records for delivering the capacity they are contracted for, instead of continuing to focus mostly on who can deliver the cheapest resource. This, however, would likely lead to further market concentration.

Another DRP said that inaccurate bidding is likely a result of having to forecast capacity far in advance. They said that pushing bidding out further will likely result in DRPs not being so aggressive with their bids, as they will have a more accurate picture of the capacity they are capable of delivering. One DRP suggested there should be a true-up period to modify bids later in the year to correct for inevitable customer churn, rather than having to back fill the capacity. Three of the DRPs suggested that allowing for payment for capacity above the contracted amount would lead to more accurate bids, as this would give companies the ability to over-enroll and provide a buffer should customers drop out or become ineligible due to a tariff change.

4.4.7 Expectations about DRAM Future

The DRPs were asked to provide their general expectations about DRAM's future. Five of the seven interviewees said that they aren't sure if DRAM will continue to get renewed, which makes it difficult to set expectations. One DRP said, "We originally thought there'd be 1,000 MW in the program by now and it'd be easy, but instead we fight for an opportunity to participate in a State that wants to be carbon-free." Another DRP said that so many changes to the program year-to-year makes it difficult to set expectations for their business and their customers, noting the program feels more like a "perpetual pilot."

Many of the interviewees pointed to CBP, especially in PG&E territory with the elect option, as just as good an opportunity as DRAM without the additional hurdles, longer timelines, and need for a scheduling coordinator. The pros and cons list comparing DRAM to the utility programs has shifted over the years, with far less reason for customers to want to be in DRAM. One DRP said "For a long time, the longer lead time was the biggest negative to DRAM. You weren't going to get called for as many events, and pricing was better. But we've seen depressed prices in recent years, particularly in SCE's territory, and a lot of the benefits of DRAM have slowly deteriorated." Another DRP said that if SCE and SDG&E provide an elect+ option in the future similar to PG&E, they will probably stop participating in DRAM and stick to CBP. On the other hand, one DRP said that DRAM and CBP can coexist because they are each better for different types of customers, with DRAM better for year-round, steady curtailment and CBP better for seasonal or weather-dependent customers.

Most DRPs held positive views on the program overall and want to see the program extended, improved, and grow over time. Many spoke very positively of the opportunity to participate in an open demand response market outside of the utility programs and were appreciative of the chance to provide input on the direction the program goes in the future.

4.5 Discussion

The 2016-2019 (III-B) DRAM pilots engaged *[REDACTED]* new third-party providers as DRAM bidders, of which ten of these DRPs won contracts during the auctions. Between 2019 (IV)-2021, there were *[REDACTED]* DRPs engaged in the DRAM auctions of which *[REDACTED]* had not previously won a DRAM contract. Nine DRPs won a contract between 2019 (IV)-2021 DRAM, of which two had not previously held a contact in 2016-2019 (III-B) DRAM.

With fewer DRPs participating in the DRAM program, there was significant concentration in the contract holders. As the residential market shrunk over the years[17], fewer DRPs bid into the residential markets. During the 2019 (IV)-2021 evaluation period, OhmConnect was the only residential contract holder in DRAM. While there were more DRPs holding non-residential

[17] Less than 60 MW of total residential capacity in both DRAM V and DRAM VI, compared to over 1 GW of non-residential contracts in those waves.

contracts, a large share of capacity and contract value was concentrated with the largest DRPs. In 2019 DRAM (IV), seven DRPs held non-residential contracts, but over *[REDACTED]* of the contracted capacity was held by one DRP, *[REDACTED]*, with *[REDACTED]* being the second highest at *[REDACTED]*. In 2020 DRAM, Leap was the largest DRP and held 36% of the contracted capacity. Along with Tesla and Voltus, the three largest DRPs controlled about 74% of the 2020 DRAM contracted capacity. A similar trend continued in 2021 DRAM when six DRPs held non-residential contracts, but the market was even more concentrated with the three largest DRPs holding 87% of the non-residential contracted capacity.

While the lack of new market participants and highly concentrated market can be seen as a concerning sign, there has been significant improvement in the viability of the DRPs holding DRAM contracts. From 2016-2019 (III-B) DRAM contract terminations, reassignments, and DRPs wholly leaving DRAM before their contract term was a regular occurrence. From 2018-2019 DRAM (IV) there was only one contract reassignment and one contract termination, both in 2019 (IV). Every DRP completed its contract term in 2020 and 2021 DRAM[18]. It can be concluded that although the market is concentrating around fewer, larger DRPs, the remaining sellers are more likely to complete their contract terms.

DRPs shared their perspective on several IOU and CAISO integration challenges faced during 2019 (IV)-2021 DRAM. In many cases, these barriers may have directly impacted a seller's performance or contributed to further market concentration. There are four main themes to the integration challenges: unpredictability of the program, lack of support from the IOUs, need for greater flexibility, and administrative burden.

Several DRPs discussed a variety of challenges with DRAM that make the program unpredictable, which makes participation riskier and lowers overall performance. One of the primary barriers leading to unpredictability is the short-term contracts and variability in prices, which results in DRPs investing less time and resources into each wave than they would if they had a guaranteed multi-year revenue stream. This also lowers customer satisfaction and increases churn. All seven of the DRPs interviewed agreed that the bidding process needs more transparency, which would prevent them from having to undervalue resources in hopes of winning a contract. Since prices have fallen in recent years, the list of advantages DRAM had over utilities programs has decreased.

Most DRPs said cooperation and support from the IOUs needs to improve. All seven interviewees expressed concern about receiving inaccurate meter data from the utilities, rarely with enough time to meet deadlines for submitting invoices and quarterly reports. The effort to correct for various data inaccuracies can be substantial, which creates additional delays even after data is received. All told, these delays can result in delayed or loss of revenue, late payments to customers, inability to review performance to improve in subsequent months, and even fines for late quarterly reports, late resettlements, or not meeting the minimum delivery requirement of 30 MWh per MW of qualifying capacity. Some DRPs suggested they should not

[18] *[REDACTED]*

incur penalties that are a result of delayed data delivery and that the IOUs should have financial obligation to improve this process, which is discussed in more detail in Section 9.6. The DRPs also pointed to the need for better standardization across the IOUs, including data access and formats, customer registration, bidding processes and timelines, and reporting requirements. Improved standardization is one suggested improvement might improve DRP diversity, as it would benefit new DRPs just as much as active sellers.

The sellers expressed a need for greater flexibility, referencing several challenges with DRAM restrictions that impact seller performance. First, the number of baselines DRPs must choose from needs to be expanded to better represent performance for a wide variety of customer loads and technologies. Further, many hoped the uncapped adjustment that was implemented during the 2020 heat waves will be made permanent, as it more accurately reflects performance for weather-dependent loads. Two of the DRPs interviewed leverage technologies such as behind-the-meter storage and electric vehicle charging, which would both benefit from the ability to use the MGO protocol to measure performance. A couple of the interviewees mentioned the program should allow net export from BTM DERs to count towards demand response performance, as many customers are unwilling to participate knowing they won't be fully compensated for what they offer the grid.

All seven DRPs discussed the amount of operational burden necessary to participate in DRAM compared to similar demand response programs. In some ways, the refinement of rules and processes since the pilot began has improved DRP viability, seen by the decrease in contract terminations and reassignments. However, these same rules that might have weeded out "bad actors" make it challenging for new aggregators to join, as it takes time and resources to automate processes or understand procedures. Further, this administrative burden may also lead to reliable DRPs leaving to participate in other programs. One DRP mentioned the administrative burden scales proportionally with the number of customers in a portfolio, which favors companies specializing in non-residential demand response that aggregate greater capacities from fewer customers.

While there are several challenges left to resolve in DRAM, the DRPs still view the program positively and would like it to continue. The DRPs appreciate the opportunity to participate in an open demand response market and a groundbreaking program in which their suggested improvements are valued.

5 Criterion 2: Were New Customers Engaged?

Criterion 2 assesses whether DRAM engaged new customers that had never participated in an IOU DR program. In the initial evaluation by the Energy Division, this criterion was graded as pass/fail, with the threshold for a 'pass' being the verification of at least one new customer participating in DRAM.

The 2019 Energy Division DRAM Evaluation found that 2016 and 2017 DRAM were "highly successful" in engaging new customers to participate in demand response. The data showed that 95% of customers in 2016 DRAM were new to DR, followed by 74% of customers in 2017 DRAM. The number of DRAM participants increased from approximately 12,500 in the first year to more than 52,000 in the second year. The first two years of DRAM saw participation increase among low income (CARE/ESA), multifamily, and net energy metered (NEM) customers. However, the overall percentages of low-income, multifamily, and NEM customers decreased in the second year. Between both years, 98% of participants were residential customers, approximately 45% were multifamily residents, and 31% were enrolled in California Alternate Rates for Energy (CARE), the discounted rate program for low-income residential customers.

The Nexant Team evaluated this criterion using a similar metric as the previous evaluation, verifying that at least one new customer participated in 2018 DRAM through 2020 DRAM. One change to the metric, due to unavailable customer participation data before 2018, is that a "new" customer is one that had not yet participated based on 2018 enrollment data. Further, 2021 DRAM is not included because customer data was not available at the time of this evaluation. Table 5-1 and Table 5-2 below show DRAM enrollment by various customer characteristics for 2016-2020 by count and percentage of total, respectively. DRAM enrollment increased by about 50,000 customers in both 2018 and 2019 (DRAM III-B+IV), peaking at around 150,000 total participants in 2019. However, overall participation halved in 2020 with 80,000 fewer residential customers enrolled in DRAM as the non-residential sector began making up a larger share of overall capacity (see Section 4.2.2). Enrollment trends among low-income (CARE) and NEM customers followed a similar pattern, increasing in 2018 and 2019, but decreasing in 2020 coinciding with the overall lower participation among the residential sector. However, the percentage of customers from these two groups increased by 1-2% each year, even in 2020. Due to lack of available data, Nexant was not able to compare dwelling types (single family and multifamily), Energy Savings Assistance (ESA), and agricultural customers to the 2016 and 2017 DRAM customer counts. However, two new customer characteristics were analyzed in this evaluation: customers on electric vehicle (EV) rates and battery storage owners.

Table 5-1: DRAM Customer Characteristics, 2016–2020

Customers	2016 DRAM (I)	2017 DRAM (II)	2018 DRAM (III-A)	2019 DRAM (III-B+IV)	2020 DRAM (V)
DRAM Customers	12,513	52,260	104,945	149,976	70,484
New DRAM Customers*	N/A	N/A	N/A	61,130	18,440
Residential	12,242	51,324	103,895	148,171	68,473
Non-Residential	271	936	1,050	1,805	2,011
CARE Rate	3,965	15,603	32,094	49,849	24,406
NEM Rate	912	2,385	10,741	17,558	9,499
EE Participant	1,735	5,612	10,808	14,972	3,451
EV Rate	N/A	N/A	2,390	4,066	2,052
Battery Storage	N/A	N/A	476	895	637

*For 2019, new DRAM customers are those that had not participated in DRAM previously based on 2018 enrollment data. New DRAM customers in 2020 were not participants in either 2018 or 2019 (III-B+IV) DRAM.

Table 5-2: DRAM Customer Characteristics, Percentages

Customers	2016 DRAM (I)	2017 DRAM (II)	2018 DRAM (III-A)	2019 DRAM (III-B+IV)	2020 DRAM (V)
DRAM Customers	12,513	52,260	104,945	149,976	70,484
New DRAM Customers	N/A	N/A	N/A	41%	26%
Residential	98%	98%	99%	99%	97%
Non-Residential	2%	2%	1%	1%	3%
CARE Rate	32%	30%	31%	33%	35%
NEM Rate	7%	5%	10%	12%	13%
EE Participant	14%	11%	10%	10%	5%
EV Rate	N/A	N/A	2%	3%	3%
Battery Storage	N/A	N/A	0.5%	0.6%	0.9%

Table 5-3 presents a comparison of DRAM customers with all customers across the three IOUs in California (PG&E, SCE, and SDG&E). As shown in the comparison, the rate of non-residential customers in DRAM is consistently lower than the overall IOU population. The share of non-residential customers increases in 2020, which is most likely explained by DRAM targeting large electricity users capable of providing substantial load curtailment. The share of CARE customers is slightly higher among DRAM customers than the IOU population, with the share of CARE customers in DRAM and the IOU population were 36% and 30%, respectively in 2020.

Table 5-3: Comparison of DRAM Customer Characteristics to the IOU Population

Characteristic	2018 DRAM (III-A)		2019 DRAM (III-B+IV)		2020 DRAM (V)	
	DRAM Customers	All IOU Customers	DRAM Customers	All IOU Customers	DRAM Customers	All IOU Customers
Total Customers	104,945	10,866,895	149,976	10,951,699	70,484	10,991,061
Residential	99%	89%	99%	89%	97%	89%
Non-Residential	1%	11%	1%	11%	3%	11%
CARE	31%	27%	34%	29%	36%	30%
NEM	10%	10%	12%	10%	14%	11%
EE Participant	10%	3%	10%	3%	5%	3%
EV Rate	2%	1%	3%	1%	3%	1%
Battery Storage	0.5%	0.3%	0.6%	0.3%	0.9%	0.3%

5.1 2018 DRAM (III-A) Customer Profile

Over 99% of DRAM customers in 2018 were residential customers, with less than 1% coming from the non-residential sector. 2018 DRAM marked the largest year-over-year increase in total DRAM customers to date, doubling from about 52,000 in 2017 to almost 105,000 in 2018. Nearly all the growth occurred in the residential sector.

The number of new DRAM customers was not quantified for 2018 DRAM because data reporting individual customer enrollment for 2016-2017 DRAM was unavailable. Without this information, it was unclear if a customer considered new to California IOU DR programs had previously participated in 2016 or 2017 DRAM. Therefore, 2018 serves as the baseline year for this metric for new DRAM participants in 2019.

Participation among low-income customers is represented by those enrolled on a CARE rate. CARE customers represented 31% of all DRAM enrollment in 2018, a slight increase from 2017 (30%). The fraction of NEM customers increased dramatically, making up 10% of all customers compared to only 5% in 2017. Table 5-4 shows the overall customer counts and percentages for 2018 DRAM.

Table 5-4: 2018 DRAM Customer Profile

Customers	2018 DRAM (III-A) Customer Counts	Percentage
DRAM Customers	104,945	100%
New DRAM Customers	N/A	N/A
Residential	103,895	99%
Non-Residential	1,050	1%
CARE Rate	32,094	31%
NEM Rate	10,741	10%
EE Participant	10,808	10%
EV Rate	2,390	2%
Battery Storage	476	0.5%

5.1.1 2018 DRAM Customer Profile by IOU

Table 5-5 displays the 2018 DRAM participant counts and percentages by IOU. PG&E had the highest enrollment, with over 60% of both the overall and residential customer participation in 2018.

CARE enrollments were highest as a percentage of total participants in SCE's territory, at 43%. PG&E had the lowest share of low-income customer participation at 27% of residential enrollment. Non-residential customer participation was highest in SCE's territory at 4%, compared to PG&E and SCE where these customers made up less than 1% of the total DRAM population.

PG&E had the largest share of customers who had participated in an EE program, with about 14% of their DRAM population. This is much higher than in SCE's and SDG&E's territories, where 1% and 7% of customers participated in EE programs, respectively.

Participation among NEM customers was similar in all three IOU territories, with PG&E having the highest percentage at 11%, down to a low of 9% in SDG&E's territory. 2018 is the first year where participation among electric vehicle and battery storage owners was evaluated. PG&E had the largest share of EV customers with about 3% of its DRAM participants on an EV rate. Customers owning a battery storage system comprised less than 1% of all DRAM participants in all three IOU service territories.

Table 5-5: 2018 DRAM Customer Profile by IOU

2018 DRAM (III-A) Customer Segment	PG&E		SCE		SDG&E	
	Count	Percentage	Count	Percentage	Count	Percentage
DRAM Customers	63,824	100%	21,571	100%	19,550	100%
New DRAM Customers	N/A	N/A	N/A	N/A	N/A	N/A
Residential	63,623	99.7%	20,742	96%	19,530	99.9%
Non-Residential	201	0.3%	829	4%	20	0.1%
CARE Rate	17,364	27%	9,009	43%	5,721	29%
NEM Rate	6,867	11%	2,099	10%	1,776	9%
EE Participant	9,205	14%	269	1%	1,334	7%
EV Rate	1,841	3%	163	0.8%	386	2%
Battery Storage	349	0.5%	71	0.3%	56	0.3%

Table 5-6 shows a comparison of DRAM to the total population for each IOU in 2018. SCE had the largest share of non-residential DRAM customers, encompassing about 4% of their DRAM population, but is still lower than the 14% of non-residential customers in the overall SCE population. Non-residential customers made up about 9% of the PG&E and SDG&E populations in 2018, but this group accounted for less than 1% of DRAM participants in both service territories. The CARE population was largest for SCE DRAM customers, with about 43% of the DRAM participants being on the CARE rate, compared to about 31% of the SCE population enrolled in the CARE rate. PG&E had a much higher percentage of EE participants enrolled in DRAM (14%) than the overall population (5%).

Table 5-6: 2018 DRAM and IOU Population Customer Profile

2018 DRAM (III-A) Customer Segment	PG&E		SCE		SDG&E	
	DRAM Customers	All PG&E Customers	DRAM Customers	All SCE Customers	DRAM Customers	All SDG&E Customers
Total Customers	63,824	5,097,748	21,571	4,318,212	19,550	1,454,188
Residential	99.7%	91%	96%	86%	99.9%	91%
Non-Residential	0.3%	9%	4%	14%	0.1%	9%
CARE	27%	26%	43%	31%	29%	21%
NEM	11%	10%	10%	8%	9%	11%
EE Participant	14%	5%	1%	1%	7%	2%
EV Rate	3%	1%	1%	0.4%	2%	1%
Battery Storage	0.5%	0.3%	0.3%	0.2%	0.3%	0.2%

5.2 2019 DRAM (III-B+IV) Customer Profile

Since the DRAM waves did not align with the calendar year, the 2019 customer analysis encompasses two DRAM waves: DRAM III-B and DRAM IV. Customers that may have been enrolled in both DRAM waves are counted as one customer in the 2019 customer analysis.

Similar to 2018, over 99% of DRAM participants in 2019 were residential customers. Compared to 2018, the number of total DRAM customers increased by about 50% from about 100,000 in 2018 to almost 150,000 in 2019. This represented the highest overall enrollment in the DRAM program in terms of customer count, as the contracts in 2020 largely shifted from the residential sector to non-residential customers, as discussed in Section 4.2.2.

An analysis of customers new to DRAM was performed for 2019, using 2018 customer participation as a baseline. By this metric, over 64,000 of 2019 DRAM customers, or 43%, had not participated in DRAM in 2018. This finding shows that DRAM continued to be successful in engaging new participants well into its fourth year.

The participation of low-income customers increased slightly to 34% of all customers in 2019, up from 31% in 2018. The fraction of NEM customers continued to increase, up to 12% of all customers in 2019. Nearly 3% of all DRAM customers were enrolled on an EV rate. Table 5-7 shows the overall customer counts and percentages for 2019 DRAM.

Table 5-7: 2019 DRAM (III-B+IV) Customer Profile

Customers	2019 DRAM (III-B+IV) Customer Counts	Percentage
DRAM Customers	149,976	100%
New DRAM Customers	64,325	43%
Residential	148,171	99%
Non-Residential	1,805	1%
CARE Rate	49,849	34%
NEM Rate	17,558	12%
EE Incentive	14,972	10%
EV Rate	4,066	3%
Battery Storage	895	0.6%

5.2.1 2019 DRAM (III-B+IV) Customer Profile by IOU

Table 5-8 displays the 2019 DRAM (III-B+IV) participant counts and percentages by IOU. As in 2018, PG&E had the largest share of 2019 enrollments, with over 95,000 customers participating in DRAM. Enrollment increased by about 50% in both PG&E and SCE territory in 2019, while enrollment increased by 13% in SDG&E territory.

SCE continued to have the highest proportion of low-income participants, with over 40% of its DRAM customers also enrolled on the CARE rate in 2019. The share of CARE-enrolled customers was slightly lower in the PG&E and SDG&E service area, where CARE customers made up about 30% of the DRAM participant population.

Similar to 2018, SCE had the largest share of non-residential customers, at about 4% of their total 2019 DRAM enrollment. This share is larger than PG&E and SCE, where non-residential customers made up less than 1% of the total DRAM population.

In 2019, PG&E had the largest share of customers who had previously participated in EE programs, at about 15% of their DRAM population. SCE remained about the same as 2018, with 1% of their DRAM enrolled customers also participating in an EE program. The share of EE participants enrolled in DRAM dropped in the SDG&E service territory from about 7% in 2018 down to 2% in 2019.

The greatest increase in the percentage of NEM customers occurred in SDG&E territory, at 12% of all DRAM participants (up from 6% in 2018). NEM customers made up 12% and 10% of all participants in PG&E's and SCE's territories, respectively. Like in 2018, PG&E and SDG&E had the largest share of EV customers where about 3% of DRAM participants were on an EV rate. Less than 1% of customers in all three IOU service territories owned a battery storage system in 2019.

Table 5-8: 2019 DRAM (III-B+IV) Customer Profile by IOU

2019 DRAM (III-B+IV) Customer Segment	PG&E		SCE		SDG&E	
	Count	Percentage	Count	Percentage	Count	Percentage
DRAM Customers	95,576	100%	32,361	100%	22,039	100%
New DRAM Customers	40,030	42%	11,364	35%	9,736	44%
Residential	95,190	99.6%	30,959	96%	22,022	99.9%
Non-Residential	386	0.4%	1,402	4%	17	0.1%
CARE Rate	30,118	32%	13,156	42%	6,575	30%
NEM Rate	11,654	12%	3,188	10%	2,716	12%
EE Incentive	14,115	15%	481	2%	376	2%
EV Rate	3,127	3%	279	1%	660	3%
Battery Storage	656	0.7%	119	0.4%	120	0.5%

Table 5-9 presents a comparison between the 2019 DRAM (III-B+IV) customers and the total population of the three California IOUs. Similar to 2018, the non-residential participation rate in DRAM is much smaller than the share of non-residential customers in the IOU population. The percentage of share of DRAM customers on the CARE rate is also similar to 2018, with the smallest difference of about 4% happening in the PG&E service territory. There is a notable increase in the amount of DRAM participants with a NEM system. While NEM customer participation in DRAM is about even with their share of the total population, the share of NEM participation in DRAM increased in every jurisdiction compared to 2018. There is also a larger share of EV customers that were enrolled in DRAM in 2019 compared to 2018, with all jurisdictions having a higher share of EV owners participating in DRAM compared to their overall population.

Table 5-9: 2019 DRAM (III-B+IV) and IOU Population Customer Profile

2019 DRAM (III-B+IV) Customer Segment	PG&E		SCE		SDG&E	
	DRAM Customers	All PG&E Customers	DRAM Customers	All SCE Customers	DRAM Customers	All SDG&E Customers
Total Customers	95,576	5,109,584	32,361	4,367,178	22,039	1,478,237
Residential	99.6%	91%	96%	86%	99.9%	91%
Non-Residential	0.4%	9%	4%	14%	0.1%	9%
CARE	32%	28%	42%	32%	30%	22%
NEM	12%	11%	10%	9%	12%	13%
EE Participant	15%	5%	2%	0.8%	2%	0.7%
EV Rate	3%	1%	0.9%	0.4%	3%	1%
Battery Storage	0.7%	0.3%	0.4%	0.2%	0.5%	0.4%

5.3 2020 DRAM (V) Customer Profile

In 2020, the total number of participants fell sharply from a high of almost 150,000 in 2019 customers down to about 70,000 customers. Residential customers remained the largest share of participants at 97%, but the number of non-residential customers increased by 9% compared to 2019 and made up a larger portion of total enrollment than any previous DRAM wave, at 3%. New customers, who were not DRAM participants in 2018 or 2019, represented about 26% of all DRAM participants in 2020, down from about 41% in the previous year. Note that 2020 DRAM only encompassed the seven months from June to December.

Regarding low-income participation, DRAM customers enrolled in CARE represented 35% of all customers in 2020, the highest to date. The share of DRAM participants enrolled in a NEM or EV rate in 2020 remained about the same as 2019 at 13% and 3%, respectively. The fraction of customers owning battery storage systems did not increase in 2020, representing about 1% of the total DRAM population. Table 5-10 shows the overall customer counts and percentages for 2020 DRAM.

Table 5-10: 2020 DRAM Customer Profile

Customers	2020 DRAM (V) Customer Counts	Percentage
DRAM Customers	70,484	100%
New DRAM Customers	18,440	26%
Residential	68,473	97%
Non-Residential	2,011	3%
CARE Rate	24,406	35%
NEM Rate	9,499	13%
EE Program Participant	3,451	5%
Electric Vehicle Rate	2,052	3%
Battery Storage	637	0.9%

5.3.1 2020 DRAM Customer Profile by IOU

Table 5-11 displays the 2020 DRAM participant counts and percentages by IOU. About 97% of DRAM participants in 2020 were residential customers, with the remaining 3% in the non-residential customer class. Overall enrollment was down in PG&E's and SDG&E's territories compared to 2019, especially PG&E which saw a decrease of 91%, making up the lowest overall share of DRAM customers (13%). Participation in SCE's territory increased by 31% and made up over 60% of the total population in 2020.

Participation among low-income customers in SCE's and SDG&E's territories remained about the same from 2019 to 2020, with SCE still having the largest portion of CARE-enrolled customers. PG&E saw a sharp decline in low-income DRAM customers, declining from about 30% of the population in 2019 down to 12% in 2020.

2020 marked a notable increase in enrollment of non-residential customers, with increases of 48% and 1,194% in PG&E's and SDG&E's territories, respectively. PG&E had the largest share of non-residential participants, representing 6% of their total 2020 population. This share was higher than SCE and SDG&E, where non-residential customers made up 3% and 1% of the population, respectively.

In 2020, PG&E had the largest share of customers who had previously participated in an EE program, at about 34% of their total population. PG&E also had the largest share of new customers, with over 40% being new to DRAM in 2020.

About 11% of customers in PG&E's territory were enrolled in an EV rate, representing a large increase compared to 2019 (3%). The increase in EV ownership along with the decrease in low-income PG&E participation could suggest that in 2020, DRPs in the PG&E service area enrolled more high-income customers into DRAM.

Table 5-11: 2020 DRAM Customer Profile by IOU

2020 DRAM (V) Customer Segment	PG&E		SCE		SDG&E	
	Count	Percentage	Count	Percentage	Count	Percentage
DRAM Customers	8,875	100%	42,379	100%	19,230	100%
New DRAM Customers*	3,748	42%	12,357	29%	2,335	12%
Residential	8,303	94%	41,143	96%	19,027	99%
Non-Residential	572	6%	1,236	3%	203	1%
CARE Rate	1,014	12%	17,435	42%	5,957	31%
NEM Rate	2,481	30%	3,909	10%	3,109	16%
EE Incentive	2,825	34%	559	1%	67	0.4%
EV Rate	926	11%	393	1%	733	4%
Battery Storage	286	3%	160	0.4%	190	1.0%

*New DRAM customers in 2020 are those that did not participate in 2018 or 2019 (III-B+IV) DRAM

A comparison of DRAM customers and the IOU population in 2020 is presented in Table 5-12. In 2020, there was a notable decrease in the total number of DRAM customers, as residential customers started to take up a smaller share of the DRAM participant population. In the PG&E service territory, 6% of DRAM customers were non-residential, the largest proportion seen in any jurisdiction from 2018 to 2020. PG&E also had the lowest share of customers that were enrolled in the CARE rate, accounting for about 12% of the DRAM customers, which is much lower than the PG&E population share of CARE customers which was about 28%. PG&E also had disproportionately high shares of NEM, EV, and storage customers enrolled in DRAM compared to their population. The SCE and SDG&E service territories did not see the same large changes in DRAM enrollment between 2019 and 2020 that were seen in PG&E.

Table 5-12: 2020 DRAM and IOU Population Customer Profile

2020 DRAM(V) Customer Segment	PG&E		SCE		SDG&E	
	DRAM Customers	All PG&E Customers	DRAM Customers	All SCE Customers	DRAM Customers	All SDG&E Customers
Total Customers	8,875	5,038,116	42,379	4,472,708	19,230	1,483,533
Residential	94%	91%	97%	87%	99%	91%
Non-Residential	6%	9%	3%	13%	1%	9%
CARE	12%	28%	42%	33%	31%	24%
NEM	30%	11%	10%	9%	16%	15%
EE Participant	34%	5%	1%	0.7%	0.4%	0.2%
EV Rate	11%	1%	1%	0.5%	4%	2%
Battery Storage	3%	0.3%	0.4%	0.2%	1.0%	0.5%

5.4 High and Low Energy Usage Customers in DRAM

One goal of DRAM pilots was to enroll customers with high energy usage. Using annual electricity usage data for all customers in PG&E and SCE service territories, the Team determined what fraction of DRAM participants were among the highest 5% of energy users for their customer segment. As discussed in Energy Division's prior Evaluation Report, data was not available for SDG&E customers in 2016 and 2017, and the Team found that the subsequent data was not reliable for 2018 through 2020.

Compared to the initial DRAM pilot in 2016, the DRPs have successfully enrolled more high energy usage customers in their respective class. PG&E and SCE doubled the share of customers with high energy usage between the first DRAM year in 2016 and 2018. In the PG&E service territory, the share of high energy users participating in DRAM continued to grow into 2020 where 10% of DRAM participants are in the top 5% of electricity users.

Table 5-13: DRAM Customers in Top Five Percent of Energy Usage for Customer Class

Year	PG&E		SCE	
	Count	Percentage	Count	Percentage
2016	560	3%	894	4%
2017	N/A	N/A	N/A	N/A
2018	3,848	6%	1,861	9%
2019	6,202	6%	2,769	9%
2020	878	10%	3,247	8%

Table 5-14 shows the percentage of DRAM participants in the lowest quartile (25%) of energy use in their respective customer class. The proportion of these low usage customers remains relatively stable across the three years of the evaluation period, ranging from 7% to 10% in PG&E and 8% to 9% in SCE.

Table 5-14: DRAM Customers in the Lowest Quartile of Energy Usage for Customer Class

Year	PG&E		SCE	
	Count	Percentage	Count	Percentage
2018	6,617	10%	1,722	8%
2019	6,953	7%	2,580	8%
2020	788	9%	3,662	9%

Table 5-15 and Table 5-16 show the percentage of low energy and high energy users in each DRP's portfolio for residential and non-residential customer classes, respectively. In the residential customer class, the percentage of high and low energy users is similar between the two DRPs, *[REDACTED]* and *[REDACTED]*, and relatively consistent over time. In the non-residential customer class, one DRP, *[REDACTED]*, shows a much higher proportion of customers in the lowest usage quartile and a much lower proportion of customers in the highest 5% of energy usage. This suggests that this DRP's non-residential customers tend to be on the smaller side of the spectrum in terms of energy usage compared to other DRAM customers.

Table 5-15: Residential DRAM Customers in the Lowest Quartile and 95th Percentile of Electricity Usage, by DRP

DRP	Lowest Quartile of Usage			95th Percentile of Usage		
	2018	2019	2020	2018	2019	2020
[REDACTED]	*[REDACTED]*			*[REDACTED]*		
[REDACTED]	*[REDACTED]*			*[REDACTED]*		

Table 5-16: Non-Residential DRAM Customers in the Lowest Quartile and 95th Percentile of Electricity Usage, by DRP

DRP	Lowest Quartile of Usage			95th Percentile of Usage		
	2018	2019	2020	2018	2019	2020
[REDACTED]	0%	0%	2%	100%	100%	84%
[REDACTED]	-	0%	0%	-	82%	81%
[REDACTED]	1%	4%	0%	79%	73%	80%
[REDACTED]	-	-	3%	-	-	77%
[REDACTED]	6%	3%	0%	70%	71%	73%
[REDACTED]	-	6%	7%	-	56%	53%
[REDACTED]	11%	20%	25%	37%	2%	1%

5.4.1 Residential CARE and NEM Customer Energy Usage

The Team collected a snapshot of CARE status for residential customers in PG&E and SCE territories as of December 2020.[19] Table 5-17 presents a comparison of monthly average electricity usage for 2020 DRAM and non-DRAM customers by their CARE status.[20] In the SCE service territory, CARE customers enrolled in DRAM had about 14% higher monthly electricity usage than CARE customers who were not in DRAM. In the PG&E service territory, CARE customers also had higher usage than non-CARE customers for both DRAM and non-DRAM customers. The difference in usage across the IOUs may stem from service area specific factors that are not accounted for in this evaluation. Electricity usage is also heavily influenced by the type of dwelling a customer lives in. Unfortunately, the IOUs did not have data available to indicate if a customer resides in a single family or multifamily dwelling, therefore the results may be skewed if one jurisdiction or segment has more multifamily customers than another.

Table 5-17: CARE Customer Usage Table (Monthly Average kWh)

Customer Segment	SCE		PG&E	
	Non-CARE	CARE	Non-CARE	CARE
Non-DRAM	577	545	385	450
DRAM Customers	567	620	392	507

[19] Historical CARE status was unavailable to conduct this analysis for 2018 and 2019.

[20] The Nexant Team received IOU demographics data in December 2020, it should be noted that due to constraints in the IOU data, a dwelling type indicator was not available for the analysis.

The Team collected a snapshot of NEM status for residential customers in PG&E and SCE territories as of December 2020.[21] Table 5-18 presents a comparison of monthly average electricity usage for 2020 DRAM and non-DRAM customers by their NEM status. NEM customers in the SCE service area had higher average electricity usage than non-NEM SCE customers. This finding was consistent for both DRAM and non-DRAM enrolled customers. Customers with a NEM system in the PG&E service area had lower average electricity usage than non-NEM customers, and much lower electricity usage (39% lower) when compared to DRAM customers without a NEM system. Similar to the CARE usage results presented in Table 5-17, the difference in usage across the IOUs may stem from differences across the service territories that are not accounted for in this evaluation.

Table 5-18: NEM Customer Usage Table (Monthly Average kWh)

Customer Segment	SCE		PG&E	
	Non-NEM	NEM	Non-NEM	NEM
Non-DRAM	554	698	415	303
DRAM Customers	578	692	458	281

5.5 Discussion

The DRAM pilots continued to engage thousands of new, primarily residential customers in demand response. Customer participation in the DRAM pilots continued to grow and nearly doubled every year from 2016 to 2019, where it peaked around 150,000 customers. 2020 saw the first decline in overall DRAM enrollments, led by a sharp fall in residential participation. This may stem from 2020 DRAM contracts focusing more on the non-residential sector where DRAM enrollment continued to grow in 2020.

DRAM continued to build upon its early success in enrolling low-income customers in DR[22]. By 2020, about 35% of DRAM customers were enrolled in the CARE rate, led by SCE's territory where over 40% of total enrollment consisted of low-income customers.

The fraction of NEM customers participating in DRAM has rose steadily since the program begin. In 2016, around 7% of all participants were NEM customers, which increased to around 13% by 2020. This aligns with general growth trends of PV in California over the last five years, which may imply these customers were not specifically targeted to join DRAM. The number of customers participating in EE programs declined over the same period, which may have more to do with the number of available programs than a lower motivation to join among that group.

The two new customer metrics analyzed in this evaluation, starting with 2018, were customers owning electric vehicles and battery storage. While there is not a high adoption rate of either technology among the general population, there was a slight increase in ownership rates of these technologies among DRAM customers between 2018 and 2020. Since both technologies

[21] Historical NEM status was unavailable to conduct this analysis for 2018 and 2019.

[22] About 32% of 2017 DRAM customers were enrolled in CARE.

can be leveraged as demand response resources, it’s likely EV and battery storage ownership rates among DRAM customers will continue to rise in the future, especially if DRPs target these customers specifically.

The 2019 Energy Division DRAM report suggested an increase in outreach to large electricity users. The Nexant Team found that customers in the top 5% of electricity usage were enrolled in DRAM at nearly double the rate that they were in 2016, which could signify that outreach efforts to enroll large electricity users in DRAM were successful.

6 Criterion 3: Were Auction Bid Prices Competitive?

The 2019 through 2021 DRAM (IV, V, and VI) procurements were carried out by the IOUs according to procedural guidelines approved by the CPUC to provide for competitive solicitations of offers for monthly resource adequacy (RA) capacity via DRAM. The auctions were conducted in 2018, 2019, and 2020, a year to six months in advance of the performance period for awarded contracts. The DRAM pilot overall is designed for stakeholders such as the CPUC, IOUs, CAISO, and DRPs to study and gain experience with direct participation of DRPs in the CAISO market. Specifically, the pilot's implementation is expected to be conducted through a competitive selection process to determine or allocate DRP participation. This section of the Nexant Team evaluation presents an assessment of the competitiveness of the IOUs Requests for Offers (RFOs).

One perspective from which to view and evaluate whether the DRAM auctions were in fact competitive solicitations is to consider the sets of bids received in the course of the auctions. The bids received in the 2019-2021 DRAM (IV-VI) RFOs can be evaluated for competitiveness on either an external or internal basis, or both. This evaluation considers both perspectives by comparing bids to external and internal benchmarks. The subsections that follow consider these quantitative metrics and comparisons to assess internal and external competitiveness separately for each DRAM procurement and separately for each IOU.

- Subsection 6.1 begins with a summary of the IOUs' auction processes for 2019-2021 DRAM (IV-VI). The bid selection procedures used by the IOUs are described and summaries of the number of bidders and bids received are presented by IOU and auction.

- Subsection 6.2 presents comparisons of average bid prices to external benchmarks of capacity resources at both the statewide and IOU-system level. These comparisons are made on an $/kW-year basis and adjusted for 2020 DRAM which had a 7-month contract performance period. These are the system resources that DER programs compete with, so to speak, in the annual development of IOU and CAISO resource portfolios to meet resource adequacy planning requirements.

- Subsection 6.3 continues with comparisons to external benchmarks pertaining to IOU DR programs. DRAM competes here with the IOUs' DR program portfolios. The Nexant Team compares average annual DRAM bid prices to annual DR program capacity payments and sets the DRAM product into context with the other programs in the IOUs' DR program portfolios – an important consideration given that program capacity payments are a function of program design.

- Subsection 6.4 concludes this section with an assessment of internal competitiveness by examining the dispersion of auction bids. Here the Nexant Team considers August bid prices ($/kW-month) to assess the extent to which the DRAM auctions approach a perfectly competitive market, where all bidders are price takers and bid price differentiation is low among market participants.

6.1 Auction Summaries

The DRAM pilot has been authorized by the CPUC and implemented by the IOUs as a mechanism to study and encourage the participation of third-party DR providers in the CAISO market. Each year that the pilot has operated, the CPUC provided procurement guidelines to the IOUs that center on budget, bid selection criteria, and timing. The IOUs then conduct their DRAM RFOs in an open and transparent manner that allows for competitive procurements.

Following the announcement for each of the RFOs, bids for 2019-2021 DRAM (IV-VI) were evaluated by the IOUs using the following procedures:

- Any non-conforming offers are identified and bidders are requested to cure non-conforming bids. Conforming monthly Proxy Demand Resource (PDR) bids must be at least 100 kW and bids may include no more than 20 offers per participant.[23]
- The Net Market Value (NMV) per Unit ($/kW-year) of each bid is calculated.
    - The NMV calculation is performed essentially in the same way by all three IOUs. PG&E provides the following definition in their annual DRAM RFO result Advice Letters.[24] NMV per Unit is defined as RA Benefits minus Offer Costs, where:
        - RA Benefits = Sum of (Offered Volume$_P$ x Product Value$_P$) where *P* is each Product;
        - Offer Costs = Sum of (Offered Volume$_P$ x Offered Pricing$_P$) where *P* is each Product; and
        - Net Market Value per Unit in $/kW-year = Net Market Value in dollars divided by Total Offered Monthly Volume in kilowatts and multiplied by 12[25] for the number of months in the contract term.
- NMVs are modified by a variety of adjustment (positive and negative) factors to account for qualitative assessment criteria; in 2021 DRAM, bidders' Qualifying Capacity (QC) estimates were assessed for viability and an NMV adjustment could also be made for bids judged to have implausible QC estimates. Bids are then sorted by their modified NMV.

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[23] 2021 DRAM also had a provision for Reliability Demand Response Resource (RDRR) bids to be at least 500 kW per month.

[24] See PG&E ALs 5284-E, 5736-E, and 5886-E.

[25] For 2020 DRAM, the multiplicative factor was 7 rather than 12.

- Bids are selected for award until the IOU's budget is spent; IOUs are not required to award contracts for bids that exceed the long run avoided cost of generation capacity (LRAC) or where one or more of the bid's monthly capacity prices is judged to be an outlier.[26] 2020 and 2021 DRAM (V and VI) procurements also had a set-aside goal of 10% of procurement going to new market entrants.

The 2019 DRAM (IV) auction opened for the three IOUs on January 25th, 2018, where DRPs submitted bids for DR capacity in calendar year 2019. DRPs with winning bids were notified on March 23rd, 2018 and were awarded with contracts for various amounts of load reduction to be delivered in 2019.

The 2020 DRAM (V) auction opened on October 11th, 2019, and DRPs submitted bids for load reduction in the seven-month period from June 2020 to December 2020. The 2020 DRAM (V) auction was unique as it did not cover a full calendar year and covered the seven-month period June through December. Winning bidders were notified of selection on December 12, 2019.

The 2021 DRAM auction opened on May 22nd, 2020, and DRPs bid load reduction that would be delivered in the 12-month period of calendar year 2021. DRPs with winning bids were notified on July 9th, 2020. Due to the DRAM stakeholders' experience of the shorter contract performance period of 2020 DRAM, a provision was made for bid selection to use an adjusted LRAC to compare to any bids for less than 12 months of capacity. The LRAC is a price benchmark for a year of generation capacity, and capacity prices are not evenly distributed across the months of a year. The LRACs the IOUs used to compare to bids for delivery periods of less than a year of contracted capacity were adjusted on a weighted basis, which reflects the IOUs' relative cost of capacity for each month of the year. For 2021 DRAM, there were a total of 60 bids at PG&E, 63 total bids at SCE, and *[REDACTED]* total bids at SDG&E. *[REDACTED]*. Table 6-1 presents summary information on the adjusted LRACs the IOUs used in evaluating 2021 DRAM bids. *[REDACTED]*. The adjusted LRACs were used for these specific bids in the bid selection process for 2021 DRAM.

Table 6-1: 2021 DRAM Bids that Utilized the Adjusted LRAC, by IOU

DRAM VI	PG&E	SCE	SDG&E
Total Number of Bids	60	63	*[REDACTED]*
LRAC ($/kW-Year)	$178.95	$178.95	$178.95
Bids for less than 12 Months of Capacity	*[REDACTED]*	*[REDACTED]*	*[REDACTED]*
Adjusted LRAC ($/kW-Year)	*[REDACTED]*	*[REDACTED]*	*[REDACTED]*

[26] 2021 DRAM bid selection guidelines also had a condition that allowed the IOUs to not select RDRR bids once the IOU's reliability cap was reached.

PG&E

A summary of the PG&E 2019 DRAM (IV) to 2021 DRAM auctions is presented in Table 6-2. In 2019 DRAM (IV), *[REDACTED]* DRPs made 81 bids into the PG&E DRAM auction. Of these bids, *[REDACTED]* of them were selected from four different bidding DRPs. The PG&E 2020 DRAM auction *[REDACTED]* bidders who made 96 bids into the market. PG&E selected *[REDACTED]* of these bids from five of the DRPs. The 2021 DRAM market had 60 bids made by *[REDACTED]*.

Table 6-2: Summary of the PG&E 2019 DRAM (IV) - 2021 DRAM Auctions

Auction Name	2019 DRAM (IV)	2020 DRAM	2021 DRAM
Auction Open Date	1/25/2018	10/11/2019	5/22/2020
Seller Selection Notification Date	3/23/2018	12/12/2019	7/9/2020
Contract Performance Period	1/2019-12/2019	6/2020-12/2020	1/2021-12/2021
Number of Bidding DRPs	*[REDACTED]*	*[REDACTED]*	*[REDACTED]*
Number of Selling DRPs	4	5	5
Total Bids	81	96	60
Shortlisted Bids	*[REDACTED]*	*[REDACTED]*	*[REDACTED]*
Winning Bids	*[REDACTED]*	*[REDACTED]*	*[REDACTED]*

SCE

Table 6-3 summarizes the SCE 2019 DRAM (IV) to 2021 DRAM auctions. In 2019 DRAM (IV) and 2020 DRAM, *[REDACTED]* DRPs submitted bids into the SCE market. Of these, six and seven DRPs had bids selected for contracts, respectively. There were 86 bids in the 2019 DRAM (IV) market of which *[REDACTED]* won a DRAM contract. In the 2020 DRAM market, 102 bids were submitted and *[REDACTED]* were selected. 2021 DRAM had *[REDACTED]* DRPs submitting 63 bids of which *[REDACTED]* were selected by SCE to receive a contract. *[REDACTED]*.

Table 6-3: Summary of the SCE 2019 DRAM (IV) - 2021 DRAM Auctions

Auction Name	2019 DRAM (IV)	2020 DRAM	2021 DRAM
Auction Open Date	1/25/2018	10/11/2019	5/22/2020
Seller Selection Notification Date	3/23/2018	12/12/2019	7/9/2020
Contract Performance Period	1/2019-12/2019	6/2020-12/2020	1/2021-12/2021
Number of Bidding DRPs	*[REDACTED]*	*[REDACTED]*	*[REDACTED]*
Number of Selling DRPs	6	7	4
Total Bids	86	102	63
Shortlisted Bids	*[REDACTED]*	*[REDACTED]*	*[REDACTED]*
Winning Bids	*[REDACTED]*	*[REDACTED]*	*[REDACTED]*

SDG&E

Table 6-4 summarizes the SDG&E 2019 DRAM (IV) to 2021 DRAM markets. In 2019 DRAM (IV), *[REDACTED]* DRPs submitted 56 bids into the DRAM market, and *[REDACTED]* of the bids were shortlisted by SDG&E for further review before the selection of *[REDACTED]* bids from three of the DRPs. In 2020 DRAM, *[REDACTED]* DRPs submitted 49 bids into the SDG&E market. *[REDACTED]* bids were shortlisted and selected from five DRPs. In 2021 DRAM, there were *[REDACTED]* bids submitted to SDG&E from *[REDACTED]* DRPs, *[REDACTED]* were selected from three of the participating DRPs. SDG&E 2019 DRAM (IV) and 2021 DRAM markets had the lowest number of winning DRPs (3) in any of the DRAM auctions going back to 2016 DRAM (see Table 4-3). *[REDACTED]*.

Table 6-4: Summary of the SDG&E 2019 DRAM (IV) - 2021 DRAM Auctions

Auction Name	2019 DRAM (IV)	2020 DRAM	2021 DRAM
Auction Open Date	1/25/2018	10/11/2019	5/22/2020
Seller Selection Notification Date	3/23/2018	12/12/2019	7/9/2020
Contract Performance Period	1/2019-12/2019	6/2020-12/2020	1/2021-12/2021
Number of Bidding DRPs	*[REDACTED]*	*[REDACTED]*	*[REDACTED]*
Number of Selling DRPs	3	5	3
Total Bids	56	49	*[REDACTED]*
Shortlisted Bids	*[REDACTED]*	*[REDACTED]*	*[REDACTED]*
Winning Bids	*[REDACTED]*	*[REDACTED]*	*[REDACTED]*

[REDACTED]. The number of DRPs winning contracts has increased for PG&E and declined SCE across the three auctions for 2019 DRAM, 2020 DRAM, and 2021 DRAM, and has not shown net growth or decline for SDG&E during that period.

The number of bids received declines between 2019 DRAM (IV) and 2021 DRAM for *[REDACTED]* of the three IOUs, but *[REDACTED]*, the number of bids does not necessarily decline year over year over that period.

6.2 DRAM Auction Bid Prices vs. Generation Capacity Cost Benchmarks

The IOUs evaluate the Net Market Value of all valid DRAM auction bids as modified by the value and risk adjustments associated with each offer that take into consideration a collection of qualitative bid evaluation criteria. The adjusted bids are then selected on a least-cost basis until the RFO's budget is exhausted, with the condition that the IOUs are not required to select any offer that exceeds the long-run avoided cost of generation capacity (LRAC). The LRAC is established by the CPUC's approved Avoided Cost Calculator (ACC) that establishes an annual cost of generation capacity that can be used to evaluate any proposed IOU DR program. The ACC is regularly updated; 2019 DRAM (IV) used an LRAC benchmark from the 2017 ACC update, 2020 DRAM used the 2019 ACC update, and 2021 DRAM used the 2020 ACC update.

DRAM offers and DRAM contracts from each RFO can also be compared to a number of other IOU and statewide system-level generation capacity benchmarks such as public and IOU-specific internal short-run resource adequacy capacity prices. Additionally, the CAISO capacity procurement mechanism (CPM) and resource adequacy adjustment incentive mechanism (RAAIM) and the CAISO Department of Market Monitoring (DMM) estimates of capacity costs for gas-fired generation can serve as external benchmarks to DRAM offer and contract prices.

These system-level benchmarks are usually expressed as annual capacity costs (kW-year), which generally makes them ready for comparison to DRAM auction prices. 2020 DRAM, however, presents an issue in that the contract performance period was not a calendar year, it was the seven-month period June 2020 to December 2020. Therefore, to compare 2020 DRAM auction prices to system-level capacity price benchmarks, the benchmarks should be adjusted for DRAM V. The Nexant Team has calculated seven-month versions of the above-mentioned benchmarks using the CPUC ED's annual Resource Adequacy (RA) reports, which provide forward projections of monthly prices for resource adequacy capacity. The 2020 DRAM procurement conducted in the fall of 2019 which means that the most recent RA Report available at the time was the 2018 RA Report. The weighted average monthly prices for the total system are used to determine the percentage of an annual 2020 IOU or system capacity price benchmark that should be used to represent a capacity price for the seven-month period June 2020 through December 2020. The Nexant Team calculates that percentage to be 62%, illustrated by Table 6-5.

Table 6-5: CPUC Short-run Capacity Costs and Normalized Monthly Shares

Month	Total-Weighted Avg. Price	Monthly Price Share
January	$2.79	8%
February	$2.79	8%
March	$2.80	8%
April	$2.79	8%
May	$2.83	8%
June	$3.04	8%
July	$3.63	10%
August	$3.73	10%
September	$3.42	9%
October	$2.97	8%
November	$2.95	8%
December	$2.91	8%
Total	**$36.65**	**100%**
Jun. - Dec. Total	**$22.65**	**62%**

Source: 2018 CPUC RA Report, published August 2019, 2020 DRAM was in procurement Oct. 2019 - Jan. 2020

In the tables of this section of the report that follow below, the benchmarks for 2020 DRAM have all been adjusted to reflect a 7-month basis. The 2020 DRAM bid and contract prices are already naturally reported on a 7-month basis.

PG&E

Table 6-6 compares the average PG&E DRAM auction prices with the avoided capacity costs and CAISO CPM, RAAIM, and estimated costs of new gas-fired capacity. *[REDACTED]*.

In 2019 DRAM (IV), the average PG&E DRAM contract price was *[REDACTED]*. There is no clear trend between residential and non-residential bids, with higher residential costs in some years and higher non-residential costs in others. The “DRAM All Offers” statistic records the average of all bids, including bids that were not selected for award. Across all six DRAM auctions, the “all offers” average is higher than the average contract price, *[REDACTED].*

Table 6-6: Summary of Average PG&E DRAM Auction Prices and Capacity Costs by DRAM Wave (All Values in $ / kW-year)

PG&E	DRAM I	DRAM II	DRAM III-A	DRAM III-B	DRAM IV	DRAM V (7 Months)	DRAM VI
Delivery Year	**2016**	**2017**	**2018**	**2019**	**2019**	**2020**	**2021**
DRAM Contracts	*[REDACTED]*						
Residential DRAM Contracts	*[REDACTED]*						
Non-Residential DRAM Contracts	*[REDACTED]*						
DRAM All Offers	*[REDACTED]*						
Long-run Avoided Capacity Costs (E3 ACC)	147.1	106.40	106.62	113.20	113.20	74.37	178.95
Public Short-run Capacity Costs (CPUC ED)	32.40	40.68	33.01	33.01	36.96	22.65	36.65
Confidential Short-run Capacity Costs (PG&E)	*[REDACTED]*						
CAISO CPM	70.66	75.68	75.68	75.68	75.68	46.92	75.68
CAISO RAAIM	70.66	45.41	45.41	45.41	45.41	28.15	45.41
CAISO DMM Estimate of New Gas-fired Capacity	166.00	166.00	145.00	114.00	114.00	71.92	Not Avail.

Figure 6-1 presents a visualization of DRAM contract prices, all DRAM offers, and the LRAC from 2016 DRAM to 2021 DRAM in the PG&E market. *[REDACTED].*

Figure 6-1: Average DRAM Bid and Contract Prices vs. the LRAC from 2016 DRAM to 2021 DRAM, PG&E

RED E D

SCE

Table 6-7 compares the average SCE DRAM auction prices with the avoided capacity costs and CAISO CPM, RAAIM, and estimated costs of new gas-fired capacity. *[REDACTED]*.

In 2019 DRAM (IV), the average SCE DRAM contract price was *[REDACTED]*, they were *[REDACTED]* in 2020 DRAM, and *[REDACTED]* in 2021 DRAM. Residential contracted capacity was more expensive than the non-residential capacity in *[REDACTED]* DRAM, *[REDACTED]*. *[REDACTED]* may have led to the higher contract prices seen in the SCE *[REDACTED]* DRAM residential market segment.

[REDACTED].

Table 6-7: Summary of Average SCE DRAM Auction Prices and Capacity Costs by DRAM Wave (All Values in $ / kW-year)

SCE	DRAM I	DRAM II	DRAM III-A	DRAM III-B	DRAM IV	DRAM V (7 months)	DRAM VI
Delivery Year	**2016**	**2017**	**2018**	**2019**	**2019**	**2020**	**2021**
DRAM Contracts (Average)	*[REDACTED]*						
Residential DRAM Contracts	*[REDACTED]*						
Non-Residential DRAM Contracts	*[REDACTED]*						
DRAM All Offers	*[REDACTED]*						
Long-run Avoided Capacity Costs (E3 ACC)	147.10	106.40	106.62	113.20	113.20	69.41	178.95
Public Short-run Capacity Costs (CPUC ED)	39.48	40.68	33.01	33.01	36.96	22.65	36.65
Confidential Short-run Capacity Costs (SCE)	*[REDACTED]*						
CAISO CPM	70.66	75.68	75.68	75.68	75.68	46.92	75.68
CAISO RAAIM	70.66	45.41	45.41	45.41	45.41	28.15	45.41
CAISO DMM Estimate of New Gas-fired Capacity	166.00	166.00	145.00	114.00	114.00	71.92	Not Avail.

Figure 6-2 visualizes the SCE DRAM contracts and received offers and compares them to the LRAC for each DRAM auction. *[REDACTED]*.

Figure 6-2: Average DRAM Bid and Contract Prices vs. the LRAC from 2016 DRAM to 2021 DRAM, SCE

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SDG&E

On average, SDG&E awarded DRAM *[REDACTED]*. In 2020 DRAM, the average contracted DRAM contract in SDG&E was *[REDACTED]*.

[REDACTED], the average bid in the *[REDACTED]* DRAM residential auction had one of the highest prices in the 2019-2021 DRAM (IV-VI) evaluation period relative to non-residential *[REDACTED]*.

[REDACTED].

Table 6-8: Summary of Average SDG&E DRAM Auction Prices and Capacity Costs by DRAM Wave (All Values in $ / kW-year)

SDG&E	DRAM I	DRAM II	DRAM III-A	DRAM III-B	DRAM IV	DRAM V (7 Months)	DRAM VI
Delivery Year	**2016**	**2017**	**2018**	**2019**	**2019**	**2020**	**2021**
DRAM Contracts	*[REDACTED]*						
Residential DRAM Contracts	*[REDACTED]*						
Non-Residential DRAM Contracts	*[REDACTED]*						
DRAM All Offers	*[REDACTED]*						
Long-run Avoided Capacity Costs (E3 ACC)	147.10	106.40	106.62	113.20	113.20	69.41	178.95
Public Short-run Capacity Costs (CPUC ED)	NA	40.68	33.01	33.01	36.96	22.65	36.65
Confidential Short-run Capacity Costs (SDG&E)	*[REDACTED]*						
CAISO CPM	70.66	75.68	75.68	75.68	75.68	46.92	75.68
CAISO RAAIM	70.66	45.41	45.41	45.41	45.41	28.15	45.41
CAISO DMM Estimate of New Gas-fired Capacity	166.00	166.00	145.00	114.00	114.00	71.92	Not Avail.

Figure 6-3 compares the SDG&E DRAM contract prices and offers to the LRAC for each DRAM wave. *[REDACTED]*.

Figure 6-3: Average DRAM Bid and Contract Prices vs. the LRAC from 2016 DRAM to 2021 DRAM, SDG&E

RED E D

Statewide

At the statewide level, neither the average DRAM offer nor awarded bid has consistently increased or decreased year-over-year across the 2019 DRAM (IV) through 2021 DRAM auctions, as shown below in Table 6-9. A key benchmark for DRAM bid prices is the LRAC, and performance of DRAM bids relative to LRAC is therefore an important indicator of bid competitiveness. There is likewise no consistent trend of improvement in average contract prices to LRAC across the 2019 DRAM (IV) through 2021 DRAM auctions. However, at the statewide average level, average DRAM contracts are more competitive with LRAC at the end of this evaluation period, 2021 DRAM, than at the beginning, 2019 DRAM (IV). The statewide average DRAM contract price is lower than the LRAC for all three auctions 2019 DRAM (IV) through 2021 DRAM.

Table 6-9: Statewide Average DRAM Auction Prices and Capacity Costs by DRAM Wave (All Values in $ / kW-year)

Statewide	DRAM IV	DRAM V (7 Months)	DRAM VI
Delivery Year	2019	2020	2021
DRAM Contracts		*[REDACTED]*	
Residential DRAM Contracts		*[REDACTED]*	
Non-Residential DRAM Contracts		*[REDACTED]*	
DRAM All Offers		*[REDACTED]*	
Long-run Avoided Capacity Costs (E3 ACC)	113.20	74.37	178.95
Public Short-run Capacity Costs (CPUC ED)	36.96	22.65	36.65
CAISO CPM	75.68	46.92	75.68
CAISO RAAIM	45.41	28.15	45.41
CAISO DMM Estimate of New Gas-fired Capacity	114	71.92	Not Avail.

6.3 DRAM Auction Bid Prices vs. IOU DR Programs

In addition to the system capacity cost benchmarks discussed in the previous section, DRAM auction bids may also be compared to the capacity payments made to participants of the IOUs' DR programs. IOU DR programs operate on a spectrum of operational models. Some programs are designed to operate in a manner that results in very little loss in value of service for participants, and some are designed to produce load reductions that require complete or near-total cessation of customer operations powered by IOU electric service. Penalties for non-performance also vary across IOU DR programs. Additionally, some programs require significant utility investment in systems and operations and maintenance (O&M) activities to build and maintain program capacity, while some programs require little to no IOU investment in equipment or O&M and instead incent the customer or implementer to invest in systems and processes to develop program capacity. This variation in IOU DR program designs is reflected in the range of program capacity payments made to program participants and DRAM auction prices should be viewed in the context of the pilot's position in the spectrum of DR program designs. As above in section 6.2, the 2020 DRAM performance period was June 2020 through December 2020, so the Nexant Team has adjusted IOU DR program capacity payments to the seven-month basis. The seven-month IOU DR program capacity payments are calculated directly from the monthly tariffed customer capacity payment levels for the months of June through December.

PG&E

Excluding pilots, pricing programs such as CPP, and air conditioning load control programs, PG&E operated two DR programs during the period 2019 through 2021: the Base Interruptible Program (BIP) and the Capacity Bidding Program (CBP). Table 6-9 presents average PG&E DRAM auction prices alongside capacity payments made to PG&E DR program participants. BIP capacity payments are the highest in the portfolio, at $102/kW-year from 2016 to 2020 and increasing to $120/kW-year in 2021. CBP participants' capacity payments have ranged from $59.39/kW-year in 2016 to $66.60/kW-year in 2021. *[REDACTED]*. For BIP, where typical load reductions are commercial/industrial process-related and not weather-driven, event notice is very short, and penalties for non-performance are high. CBP operations are more similar to DRAM because the penalties for non-performance are not as high, more load shed is weather-driven, and load reductions do not necessarily require ceasing business processes. *[REDACTED]*.

Table 6-9: Summary of Average PG&E DRAM Auction Prices and IOU DR Programs by DRAM Wave (All values in $ / kW-Year)

PG&E	DRAM I	DRAM II	DRAM III-A	DRAM III-B	DRAM IV	DRAM V (7 Months)	DRAM VI
Delivery Year	**2016**	**2017**	**2018**	**2019**	**2019**	**2020**	**2021**
DRAM Contracts	*[REDACTED]*						
Residential DRAM Contracts	*[REDACTED]*						
Non-Residential DRAM Contracts	*[REDACTED]*						
DRAM All Offers	*[REDACTED]*						
CBP-DA (participant capacity payment)[27]	59.39	62.07	62.07	62.07	62.07	63.42	66.60
BIP (participant capacity payment)[28]	102.00	102.00	102.00	102.00	102.00	70.00	120.00

SCE

SCE operated three DR programs from 2019 to 2021 (excluding pricing programs such as CPP and air conditioning cycling programs). Like PG&E, SCE offers BIP and CBP. SCE's CBP program has two options, however, a day-ahead (DA) option and a day-of (DO) option. A direct load control program for agricultural pumping loads is also in SCE's DR portfolio, the Agriculture Pumping – Interruptible (AP-I) program. The AP-I program is designed to achieve 100% load

[27] Simple average of customer incentives for Prescribed, Elect, and Elect + program options. However, during the period 2019-2021 the customer incentives are the same for all options.

[28] Simple average of customer incentives for small (1-500 kW), medium (501-1,000 kW), and large (1,001 kW and greater) load reductions.

impacts from agricultural pumping facilities, representing complete curtailment of pumping for the duration demand response events, with no opportunity for the customer to opt-out. Table 6-10 displays the average SCE DRAM auction prices and the capacity payments for SCE DR programs. AP-I customer incentives are commensurately high and are the largest of SCE's portfolio, ranging from $153.95/kW-year in 2016 to $165.44/kW-year in 2021. Like PG&E, SCE BIP incentives are also high – $129.39/kW-year in 2016 and $133.87/kW-year in 2021. *[REDACTED]*.

Table 6-10: Summary of Average SCE DRAM Auction Prices and IOU DR Programs by DRAM Wave (All values in $ / kW-Year)

SCE	DRAM I	DRAM II	DRAM III-A	DRAM III-B	DRAM IV	DRAM V (7 Months)	DRAM VI
Delivery Year	2016	2017	2018	2019	2019	2020	2021
DRAM Contracts	*[REDACTED]*						
Residential DRAM Contracts	*[REDACTED]*						
Non-Residential DRAM Contracts	*[REDACTED]*						
DRAM All Offers	*[REDACTED]*						
CBP-DA (participant capacity payment)	62.03	62.03	66.03	66.03	66.03	56.94	79.26
CBP-DO (participant capacity payment)[29]	71.31	71.31	75.91	75.91	75.91	65.47	91.10
AP-I (participant capacity payment)[30]	153.95	133.39	165.38	162.53	165.44	111.09	165.44
BIP (participant capacity payment)[31]	129.39	135.72	111.07	110.83	109.04	75.08	133.87

SDG&E

SDG&E operated two non-pricing DR programs during the 2019 through 2021 period, excluding air conditioning cycling programs, pricing programs, and pilots. Like PG&E and SCE, BIP and CBP are in SDG&E's portfolio. Table 6-11 presents SDG&E's average DRAM auction prices along with the participant capacity payments for their DR programs. Unlike SCE and PG&E, SDG&E's BIP participant incentives are comparable to CBP incentives, *[REDACTED]*. This may

[29] For 2016, simple average of customer incentives by event window option (1-4 PM, 2-6 PM, and 4-8 PM). For 2016, only one event window option is offered (1-6 PM).

[30] Simple average of customer incentives for small (less than 200 kW) and large (200 kW and greater) usage customers and weighted average of customer incentives for seasonal time-of-use period (summer on-peak and winter mid-peak). However, during the period 2019-2021 incentives for small and large usage customers are identical.

[31] Simple average of customer incentives for low (less than 2 kV), medium (2-50 kV), and high (50 kV and greater) service voltage customers; simple average of notification option A (15-minute notice) and option B (30-minute notice); and weighted average of customer incentives for seasonal time-of-use period (summer on-peak, summer mid-peak, and winter mid-peak).

be related to the fact that there is little differentiation between the target customer base for BIP and CBP at SDG&E; the San Diego service territory has fewer industrial customers than the service territories at SCE and PG&E, yielding similar load impact qualities among large commercial and light industry customers enrolled in BIP and CBP. SDG&E's BIP customer incentives started at $84/kW-year in 2016 and are $75.60/kW-year in 2021 while CBP DA and DO incentives begin at $63.45/kW-year and $76.15/kW-year in 2016, respectively, and are $75.60/kW-year and $81.01/kW-year in 2021, respectively.

Table 6-11: Summary of Average SDG&E DRAM Auction Prices and IOU DR Programs by DRAM Wave (All values in $ / kW-Year)

SDG&E	DRAM I	DRAM II	DRAM III-A	DRAM III-B	DRAM IV	DRAM V (7 Months)	DRAM VI
Delivery Year	**2016**	**2017**	**2018**	**2019**	**2019**	**2020**	**2021**
DRAM Contracts (Average)	*[REDACTED]*						
Residential DRAM Contracts	*[REDACTED]*						
Non-Residential DRAM Contracts	*[REDACTED]*						
DRAM All Offers	*[REDACTED]*						
BIP (participant capacity payment)	84.00	84.00	74.00	74.00	75.60	44.10	75.60
CBP-DA (participant capacity payment)[32]	63.45	71.50	71.50	71.50	71.50	68.36	71.50
CBP-DO (participant capacity payment)[33]	76.15	81.01	81.01	81.01	81.01	77.45	81.01

[REDACTED].

These comparisons of capacity payments and prices are useful in assessing the competitiveness of DRAM auction prices; however, program capacity payments and auction prices do not reflect the total cost to the IOUs of operating the DRAM pilot or their DR programs. Overall DR program costs and DRAM pilot costs may diverge or converge in ways that are not reflected in auction prices and customer capacity payments. However, merely comparing total DRAM pilot and DR program costs by IOU is insufficient for developing a holistic comparison of DRAM to other DR resources, which should also factor in the actual (as opposed to contracted) benefits delivered by DRAM and the other DR programs. Total costs and benefits for both DRAM and the DR programs can be integrated and fairly compared using the Energy Division-sponsored Distributed Energy Resources (DER) Cost-effectiveness (CE) Template. The DER

[32] Simple average of customer incentives for 11 AM - 7 PM and 1-9 PM program options.

[33] Simple average of customer incentives for 11 AM - 7 PM and 1-9 PM program options.

CE template is a public and relatively simple analytical tool that uses avoided cost assumptions from CPUC's most recent Avoided Cost Calculator (ACC), inputs on program costs, and inputs on ex ante program performance to model the four cost effectiveness metrics that are commonly used to evaluate IOU program proposals.[34] The Nexant Team recommends that a CE comparison of DRAM and IOU DR should be undertaken once reliable ex post and ex ante load impact estimates are available for DRAM. All-in IOU DR program costs and DRAM pilot costs should be relatively straightforward to gather; however, as demonstrated by this evaluation, reliable estimates of the benefits delivered by DRAM are a requisite ingredient for a meaningful CE analysis of DRAM alongside IOU DR programs.

6.4 Dispersal of Bids

Basic economic theory holds that in a perfectly competitive market, participating firms are "price takers," whereby in participating in the market, individual firms cannot influence the price for the goods that they have on offer.[35] A snapshot of prices offered by perfectly competitive firm in a market would show collection of offers at identical per-unit prices. Such a condition would be dependent on the basic features of perfectly competitive markets: many rival firms participating in the market, the rival firms possessing common information about the opportunities on the market, and the absence of any barriers to market entry and exit.[36] An indicator of whether or not any given market, such as the DRAM RFOs, is competitive may be proposed to be the extent of spread or dispersion of firms' offered bids. A perfectly competitive market would have no dispersion, a near competitive market would have low bid dispersion. In the context of DRAM, a complicating factor in considering bid price dispersion, however, is that prices may vary due to differing DRP product characteristics. DRP products may vary with respect to technologies used, customers targeted, and operating costs. Variation in underlying product attributes may be in effect in the same DRAM auction between DRP bids at a single IOU, and also may be in effect across auctions with respect to both time and service territory.

Table 6-12 presents the minimum bid, maximum bid, and range of bids for all August bids from 2016 DRAM to 2021 DRAM. *[REDACTED]*.

[REDACTED], as seen in Figure 6-4, which graphs the spread between minimum and maximum bids for each IOU and DRAM RFO. *[REDACTED]*.

[34] The four CE tests are the Total Resource Cost (TRC) test, the Ratepayer Impact Measure (RIM), the Program Administrator Cost (PAC) test, and the Participant Cost Test (PCT).

[35] Pepall, Richards, and Norman (2014), *Industrial Organization: Contemporary Theory and Empirical Applications*. Fifth Edition, Wiley.

[36] OECD (2021), Methodologies to measure market competition, OECD Competition Committee Issues Paper, https://oe.cd/mmmc

Table 6-12: Range of All August Offers, by IOU and DRAM Wave (2016 - 2021 DRAM)

DRAM Wave	PG&E			SCE			SDG&E		
	Min	Max	Range	Min	Max	Range	Min	Max	Range
2016 DRAM	*[REDACTED]*			*[REDACTED]*			*[REDACTED]*		
2017 DRAM	*[REDACTED]*			*[REDACTED]*			*[REDACTED]*		
2018 DRAM	*[REDACTED]*			*[REDACTED]*			*[REDACTED]*		
2019 DRAM (III-B)	*[REDACTED]*			*[REDACTED]*			*[REDACTED]*		
2019 DRAM (IV)	*[REDACTED]*			*[REDACTED]*			*[REDACTED]*		
2020 DRAM	*[REDACTED]*			*[REDACTED]*			*[REDACTED]*		
2021 DRAM	*[REDACTED]*			*[REDACTED]*			*[REDACTED]*		

Figure 6-4: Range (Difference Between Maximum and Minimum Offer) of DRAM Offers by IOU and DRAM Wave

RED E D

Table 6-13 summarizes the August bids from 2019 DRAM (IV) to 2021 DRAM. *[REDACTED]*.

Echoing the above Figure 6-4, the *[REDACTED]* with respect to the range between minimum and maximum bids in the period 2016-2021. The coefficient of variation (CV) normalizes the standard measure of dispersion about the mean to the magnitude of the mean, so that variation can be compared across datasets with different magnitudes of mean. *[REDACTED]*.

As a helpful alternative to considering the entire bid dataset, we consider the collection of bids that lie between the 25th percentile bid (the bid below which the 25% lowest bids lie) and the 75th percentile bid (the bid above which the 25% highest bids lie), called the "interquartile range" (IQR), to eliminate the influence on bid dispersion of the very lowest and highest bids. The Nexant Team has the bid data to support an assessment the interquartile range for the 2019-

2021 DRAM (IV-VI) auctions. The more competitive the DRAM RFOs are, the smaller the interquartile range will be (i.e., the central mass of the RFO bids will be contained in a tighter and tighter radius around the average bid). The Nexant Team does not propose an absolute benchmark of bid dispersion as expressed by the interquartile range, due to the fact that the presence of price differentials due to firm "markups" doesn't necessarily indicate decreased consumer welfare.[37] Instead, we propose to consider whether the interquartile range is constant or changing over time as an internal benchmark of the RFOs' relative competitiveness to each other. *[REDACTED]*.

Table 6-13: Summary Statistics of All August Offers, by IOU and DRAM RFO, from 2019 DRAM (IV) to 2021 DRAM ($/kW-month)

All Bids	PG&E			SCE			SDG&E		
	2019 DRAM (IV)	2020 DRAM	2021 DRAM	2019 DRAM (IV)	2020 DRAM	2021 DRAM	2019 DRAM (IV)	2020 DRAM	2021 DRAM
Min.	*[REDACTED]*			*[REDACTED]*			*[REDACTED]*		
Mean	*[REDACTED]*			*[REDACTED]*			*[REDACTED]*		
Max.	*[REDACTED]*			*[REDACTED]*			*[REDACTED]*		
Range	*[REDACTED]*			*[REDACTED]*			*[REDACTED]*		
Coeff. Of Variation	*[REDACTED]*			*[REDACTED]*			*[REDACTED]*		
25th-75th Interquartile Bids	**PG&E**			**SCE**			**SDG&E**		
	2019 DRAM (IV)	**2020 DRAM**	**2021 DRAM**	**2019 DRAM (IV)**	**2020 DRAM**	**2021 DRAM**	**2019 DRAM (IV)**	**2020 DRAM**	**2021 DRAM**
25th Percentile	*[REDACTED]*			*[REDACTED]*			*[REDACTED]*		
Median	*[REDACTED]*			*[REDACTED]*			*[REDACTED]*		
75th Percentile	*[REDACTED]*			*[REDACTED]*			*[REDACTED]*		
Inter-Quartile Range	*[REDACTED]*			*[REDACTED]*			*[REDACTED]*		

Figure 6-5 through Figure 6-7 visualize the data presented in Table 6-13 as box-and-whisker plots *[REDACTED]*. The box feature of the plots indicates the boundaries of the IQR for each auction, which comprise the top and bottom edges of the box. *[REDACTED]*. The lines inside the boxes show the mean August bid for each auction – *[REDACTED]*. The "X"s in the Figures indicate the median August bid price, and *[REDACTED]*. Lastly, the whisker feature of the Figures indicates the 1% and 99%-percentile bids, *[REDACTED]*.

[37] Barry, Gaynor, and Morton, *Do Increasing Markups Matter? Lessons from Empirical Industrial Organization*, Journal of Economic Perspectives – Volume 33, Number 3 – Summer 2019, pp. 44-68.

PG&E

In Figure 6-5 *[REDACTED]*.

Figure 6-5: Boxplot of August Bid Prices, PG&E

RED E D

SCE

Figure 6-6 shows *[REDACTED]*.

Figure 6-6: Boxplot of August Bid Prices, SCE

RED E D

SDG&E

Finally, Figure 6-7 displays the range of August bid prices in the SDG&E markets from 2019 to 2021 DRAM (IV-VI). *[REDACTED]*.

Figure 6-7: Boxplot of August Bid Prices, SDG&E

RED E D

Statewide

Table 6-14 presents the summary statistics of all August capacity offers for the 2019 DRAM (IV) through 2021 DRAM auctions at the statewide level. At the statewide level, the minimum bid *[REDACTED]* the maximum bid *[REDACTED]*. Considering only the middle 25th-75th percentile bids, we find the statewide IQR is decreasing over time: *[REDACTED]* in 2019 DRAM (IV), *[REDACTED]* in 2020, and *[REDACTED]* in 2021, *[REDACTED]*. The statewide IQR in 2020 was 8% lower than that in 2019 DRAM (IV) and the statewide IQR in 2021 was 21% lower than that of the 2020 DRAM.

Table 6-14: Summary Statistics of All August Offers, Statewide by DRAM RFO, from 2019 DRAM (IV) to 2021 DRAM ($/kW-month)

All Bids	Statewide		
	2019 DRAM (IV)	2020 DRAM	2021 DRAM
Min.	*[REDACTED]*	*[REDACTED]*	*[REDACTED]*
Mean	*[REDACTED]*	*[REDACTED]*	*[REDACTED]*
Max.	*[REDACTED]*	*[REDACTED]*	*[REDACTED]*
Range	*[REDACTED]*	*[REDACTED]*	*[REDACTED]*
Coeff. Of Variation	*[REDACTED]*	*[REDACTED]*	*[REDACTED]*
25th-75th Interquartile Bids	**2019 DRAM (IV)**	**2020 DRAM**	**2021 DRAM**
25th Percentile	*[REDACTED]*	*[REDACTED]*	*[REDACTED]*
Median	*[REDACTED]*	*[REDACTED]*	*[REDACTED]*
75th Percentile	*[REDACTED]*	*[REDACTED]*	*[REDACTED]*
Inter Quartile Range (IQR)	*[REDACTED]*	*[REDACTED]*	*[REDACTED]*
Year-over-year IQR Change (%)	N/A	-8%	-21%

6.5 Discussion

The bid prices submitted to the IOUs in the 2019 (IV), 2020, and 2021 DRAM RFOs provide an opportunity to evaluate a key feature of the DRAM pilot design – competitive selection of DRP pilot participants. The set of bids can be used to look for indications that the selection process is a less than competitive process for the participating bidders. Additionally, DRAM bid prices can be compared to the capacity payments made by the IOUs DR programs, which are other load-modifying resources IOUs may use to fulfill their resource adequacy planning needs. Finally, the DRAM bid prices can be compared to other electric generation capacity resource prices, for resources sourced or evaluated at the statewide or IOU system level that may be considered as alternate RA capacity resources.

The IOUs' three DRAM auctions that covered contract performance periods of 2019 (IV), 2020, and 2021 were held about six months to a year in advance of the performance periods. *[REDACTED]*. The number of DRPs winning contracts has increased for PG&E, has shown a net decline at SCE during the three year period covering the 2019 (IV) through 2021 auctions. SDG&E has not shown net growth or decline during that period.

The number of bids received declines between 2019 DRAM (IV) and 2021 DRAM for *[REDACTED]* of the three IOUs, but the number of bids does not necessarily decline year over year during that period. Declining numbers of auction bids may indicate consolidation of market participation. *[REDACTED]*.

Prices for 2019-2021 DRAM (IV-VI) winning bids *[REDACTED]*. The average awarded bid *[REDACTED]*. When considering the average of all submitted bids, not just the awarded bids, *[REDACTED]*.

At the statewide level, neither statewide average DRAM offers nor awarded bids consistently increased or decreased – there is no consistent increasing or decreasing year-over-year trend across the 2019 DRAM (IV) through 2021 DRAM auctions. A key benchmark for DRAM bid prices is the LRAC, and performance of DRAM bids relative to LRAC is therefore an important indicator of bid competitiveness. There is likewise no consistent trend of improvement in average contract prices to LRAC across the 2019 DRAM (IV) through 2021 DRAM auctions. However, at the statewide average level, average DRAM contracts are more competitive with LRAC at the end of this evaluation period, 2021 DRAM, than at the beginning, 2019 DRAM (IV). The statewide average DRAM contract price is less than LRAC for all three auctions 2019 DRAM (IV) through 2021 DRAM.

A comparison of DRAM bid prices to IOU DR program capacity payments must be made with the varying program designs in mind. DR program expectations of participants can vary from programs that give customers a great deal of flexibility in whether to shed load and how much, to others with little flexibility, such as interruptible programs that target large C&I businesses and incent near-complete curtailment of business processes and exact stiff penalties for non-performance. These differences manifest in the capacity payments offered by the programs which can be more than $100/kW-year for BIP. Average DRAM winning bid prices *[REDACTED]*. While these points of comparisons are useful, DRAM's total pilot costs (not just the capacity payments to DRPs) and DR program total costs (not just participant capacity payments) should be integrated with their delivered benefits in a cost-effectiveness analysis to fully determine how well DRAM competes for a place as a resource in the IOUs' DR program portfolios.

Finally, the range of DRAM auction bid prices can be examined for indications of trending increases or decreases in market competitiveness, where the competitive ideal of only price-taking firms would yield little to no variation of DRAM bid prices. *[REDACTED]*. At the statewide level, the minimum bid *[REDACTED]* the maximum bid *[REDACTED]*. Considering only the bids between the 25th and 75th percentile bids, we find the statewide IQR is decreasing over time: *[REDACTED]* in 2019 DRAM (IV), *[REDACTED]* in 2020, and *[REDACTED]* in 2021, *[REDACTED]*. The statewide IQR in 2020 was 8% lower than that in 2019 DRAM (IV) and the statewide IQR in 2021 was 21% lower than that of the 2020 DRAM.

7 Criterion 4: Were Offer Prices Competitive in the Wholesale Market?

Criterion 4 aims to assess whether DRAM energy bid prices were competitive in the California Independent System Operator (CAISO) wholesale energy market. There are several factors and perspectives when assessing competitiveness of bid prices. Comparing the energy bid price submitted to the market to the resource's marginal energy cost is one way in which resources are assessed for competitiveness. For example, the CAISO uses a formulaic approach to estimating the marginal cost of energy for gas-fired resources and uses that value to evaluate if resources are bidding competitively in the market. While the DRPs report their marginal cost via the DRAM quarterly reports, currently there isn't a standard methodology of estimating the marginal cost of energy for demand response resources. Therefore, as an alternative the Nexant Team looked at a few different metrics for competitiveness:

- Distribution of DRAM resource energy bid prices
    - Distribution of DRAM resource energy bid prices in the day-ahead (DA) and real-time (RT) markets
    - Comparison of DRAM resources energy bid prices between the DA and RT markets
    - Comparison of DRAM resources energy bid prices to similar participating resources
- Assessing the dispatch activity of DRAM resources based on scheduling rates
- Assessing the dispatch activity of DRAM resources based on scheduling effectiveness

7.1 Methodology and Metrics

This section describes the methodology used for each metric developed to assess the competitiveness of DRAM resources' offer prices in the CAISO wholesale energy markets. We also address the data challenges encountered in the evaluation that impacted the analysis.

7.1.1 Data Challenges

The analysis presented in this section is primarily based on a combination of CAISO bid data files and CAISO settlement data files. As the Nexant Team worked through the data to start the evaluation effort, we encountered several data challenges that required modification to either (1) the assessment or (2) the observations included in the assessment. As such the results presented below are based on the best data made available to the Team and may reach a different conclusion given a complete data set to work with that was absent missing data or mapping challenges.

As it pertains to this section of the evaluation report, there are three main areas of data challenges that directly impact these results.

- The CAISO bid data set did not include the full bid curve of all resource types which is needed to accurately capture the bid price distribution of comparable resource types. The Team addressed this by requesting data that included the full bid curve and narrowing in on the time period used for certain areas of the analysis.

- The CAISO bid data set did not include RT self-scheduled megawatts and may have also been missing RT bid curve segments entirely. This made it challenging for the Team to determine which resources received RT schedules due to economic offers versus self-scheduling DA awards in the RT market, impacting the RT scheduling rate metrics. The Team addressed this issue by only including those observations where RT economic bid curves were provided for RT metrics that relied on needing the full bid curve.

- The mapping of demand response providers to resource IDs was incomplete and inconsistent across source data. This made it challenging for the Team to ensure consistent mapping across the different underlying datasets used in this section of the evaluation.[38]

7.1.2 Metrics

Bid Distribution and Comparison

The bid distribution and comparison analysis seeks to evaluate the overall distribution of energy offers by DRAM resources into the CAISO's markets at various price points. The analysis evaluates trends over time as well as differences in offer prices between the DA and RT markets. In this metric we also observe the concentration of DRAM energy at varying price points and assess how "competitive" the offers are relative to other resource types.

This evaluation uses two different time periods for the analysis. When only evaluating DRAM resources, the analysis is based on July 2018 to December 2021 energy bid prices; when comparing to other resource types, the analysis is based on data from August 2020 to December 2021. DRAM resources, like all other resource types, have the ability to submit a bid curve with up to 10 different steps. In other words, they are able to offer megawatts at different bid prices up to the maximum amount of energy they can provide (often referred to as the maximum output or Pmax of a resource). The Nexant Team acquired CAISO bid data including the entire bid curve for the time period from August 2020 to December 2021. This allowed the Team to conduct a more accurate assessment, for 2020 and 2021, of the prices at which

[38] The datasets provided used different sources for the resource ID to demand response provider mappings. Thus, in some metrics the demand response providers are combined because that data source did not have a clean one to one mapping.

capacity is being offered into the wholesale market rather than only evaluating the maximum offer price.

The metrics within this section primarily report on MW-weighted average bid prices. The MW-weighted average bid price essentially takes each bid price in a resource's bid curve and weighs it by the MWs associated with that bid curve segment. When making comparisons to other resource types and/or across years, the MW-weighted average bid price is reflective of all the MWs offered in at various price points for that resource type and/or year; it is not the average of the resource specific MW-weighted average bid price for each trading hour.

When assessing offer price differences between the DA and RT market, the Nexant Team does this on a resource specific basis for each hour using the MW-weighted average bid price for that resource and that market. For example, the Team calculates a resource's MW-weighted average bid price in the DA market for trade hour 18. This is then compared to the MW-weighted average bid price of the same resource in the same trading hour for the RT market to determine if the resource increased or decreased its MW-weighted average bid price between the two markets.

Additionally, when evaluating the total percentage of offered in MWs by price category, the Team first categorizes each submitted bid curve segment based on the associated offer price for that segment. Then the MWs associated with each categorized offer price are summed up to determine the total MWs offered at a price within that price category.

Scheduling Rate

The scheduling rate metric seeks to test a given resource's ability in getting its available capacity scheduled in the market. The energy offers in the RT market can differ from those offers used in the DA market. Thus, for a more comprehensive measurement of the competitiveness of DRAM energy offers in the wholesale market, the scheduling rate is evaluated for both the DA and RT market. The Nexant Team evaluated the scheduling rate during the Availability Assessment Hours (AAH)[39] as well as the AAHs in the peak summer months, specifically July, August, and September

The scheduling rate is determined by dividing the aggregated energy schedule by the aggregated energy offered in the respective markets over the time period of interest. This metric is based on the CAISO data.[40]

Due to data challenges, the RT scheduling rate is limited to hours during which the CAISO data provided an economic energy offer for the DRAM resource. In other words, the RT scheduling rate does not include hours where the resource may have been awarded energy, but the bid

[39] For purposes of this analysis, Availability Assessment Hours were defined as hours ending 17-21 on non-holiday weekdays.

[40] Specifically, the day-ahead metric is the sum of DAM_DISPATCH_QTY divided by sum of max MW of the energy bid curve across the period of interest. The real-time metric uses the RTM_DISPATCH_QTY and max MW of the real-time energy bid curve when the data has an associated real-time economic bid curve for that hour.

curve was missing from the dataset or was incomplete.[41] It could also be the case that during those hours, the energy was self-scheduled in the RT market which would increase in the RT scheduling rates. However, without the RT self-scheduled data from the CAISO, the Team was unable to accurately verify in what hours the energy was self-scheduled. Thus, one could view the RT scheduling rates as a lower bound. Additionally, the scheduling rates are representative of how effective the DRAM resources were at getting the capacity scheduled in the RT market using economic offers, which one could also argue is a more accurate comparison for evaluating the competitiveness of wholesale energy offers.

Specifically, the following steps are used to determine the scheduling rate of a resource type for a specific market (i.e, DA or RT):

1. Determine the awarded energy (numerator): For a particular time period of interest (year, Availability Assessment Hours, or some other period), the energy awarded quantities (referred to as DAM_DISPATCH_QUANTITY in CAISO's bid data file for DA and RTM_DISPATCH_QUANTITY in the CAISO's bid data file for RT) are summed across all resource IDs within the resource type.

2. Determine the total energy offered (denominator): The energy quantities bid into the market were summed across the same set of resources and time period of interest. For both the DA and RT markets this is based on the last megawatt value associated with the last bid curve step in each respective market from the CAISO's bid data file.

3. Determine the "scheduling rate" by taking the ratio between the numerator and denominator from the above steps, expressed as a percentage.

Scheduling Effectiveness

The scheduling effectiveness metric seeks to test a given resource's effectiveness in getting its available capacity scheduled in the market during the 120 hours of highest CAISO system need. This metric is calculated the same as the scheduling rate metric but narrowing in on only the top 120 hours of highest CAISO system need. In this section, we present the scheduling effectiveness during the top 120 net load hours in each year from 2018-2021. Net load is defined as gross load minus wind and solar generation. The Nexant Team opted to evaluate the top 120 net load hours rather than top 120 gross load hours. This is because given the increased penetration of renewable resources, the highest need for resources that are not wind and solar, such as demand response, is during the highest net load hours as opposed to highest gross load hours.

7.1.3 Market Resource Comparison

Throughout this section, metrics for DRAM resources are compared to other participating resources in the market. When comparing DRAM resources to other participating resources, determining what the appropriate resource comparison would be is challenging given the unique

[41] The Team observed that in some cases, there was only one bid segment in the data. Based on how the energy bids are submitted to the CAISO market, one bid curve requires at least two bid segments. Thus these were considered incomplete.

nature of DRAM resources relative to the other resource types in the CAISO fleet. Thus, the Nexant Team applied a similar evaluation approach as used in the prior DRAM Evaluation.

The DRAM Research Plan proposed to evaluate the overall bidding distribution of the DRAM resources compared to a select set of other resource types – namely IOU DR resources, In Front of the Meter (IFOM) storage, and gas-fired peaker plants. Though the Nexant Team acknowledges that wholesale market offers across different resource types have some inherent differences, we believe these resource types offer the most reasonable comparison, as they are the types of resources that are either similar in nature of the underlying resource providing demand response or are the fossil fuel resources that may be replaced by demand response. The inherent differences include participation models, physical attributes, use profiles, and cost profiles. Thus, while comparing a DRAM resource to a wind or solar facility may not be meaningful, there is a subset of similarly situated resource types that can be used for comparison purposes as they are most likely the resource types, alongside DRAM resources, to be used during high system needs.[42] As such, it seems reasonable that in the absence of peaker plants and storage facilities, DRAM resources would be used to fill in the gaps.

When using IOU DR resources for comparison, the Reliability Demand Response Resources (RDRR) were excluded from the analysis since RDRRs are unable to bid less than 95% of the CAISO energy bid cap in RT. Additionally, only a subset of the IOU DR resources was provided in the datasets. Thus, the metrics related to IOU DR is not reflective of all IOU DR resources, just those that were identified as such and provided to the Nexant Team.

7.2 Bid Distribution

In this section, the Nexant Team presents the analysis regarding bid price distribution. This part of the evaluation is aimed at determining not only the offer prices being submitted into the CAISO wholesale energy market but also (1) the range of offer prices and (2) the concentration of megawatts within offer price ranges.

The Nexant Team first presents analysis on the MW-weighted average bid price from DRAM resources in both the day-ahead (DA) and real-time (RT) markets. This is then followed by a comparison to other resource types – IOU DR programs, peaker plants, and storage resources. The bid prices for storage resources are based only on the offer prices and megawatts associated with the discharging portion of its operating range. Next, the Team categorized each megawatt by the offer price into bid price categories and then determined the percentage of total megawatts offered in each bid price category (e.g., \$100 - \$250/MWh, \$250 - \$500/MWh, etc). Lastly, the Team evaluated if, how frequently, and by what magnitude DRAM resources are changing the DA offered energy price in the RT market.

Recall that the CAISO bid data for the RT market did not include the self-scheduled megawatts. Thus, the Nexant Team was unable to accurately determine megawatts offered into the RT

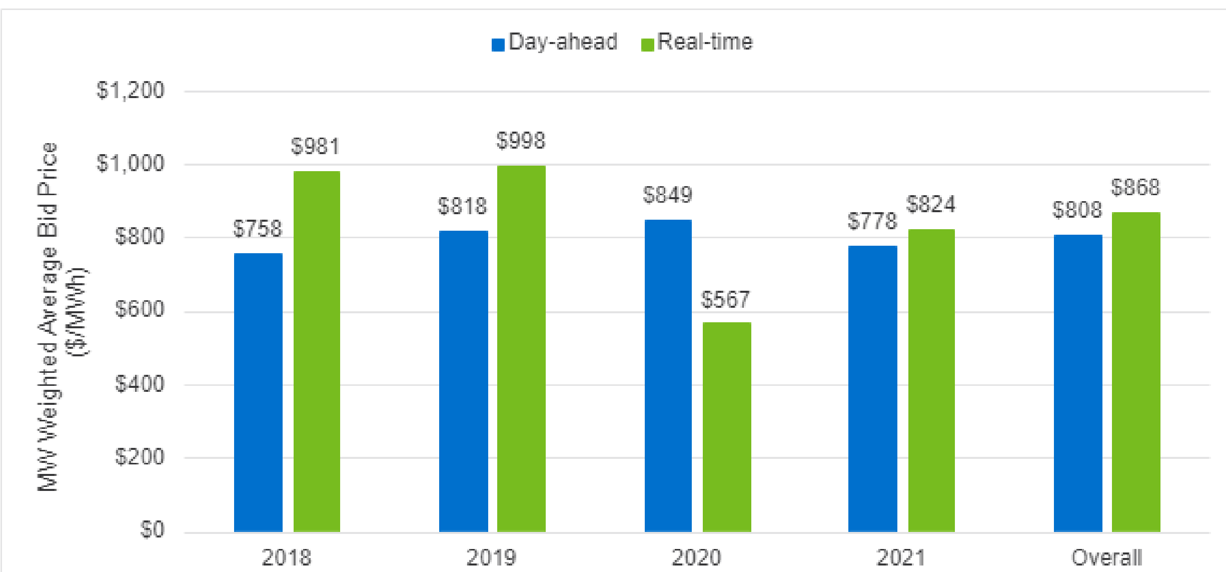
[42] In this context, high system needs refer to hours during which there is a high need for non-renewable resource types to meet load (i.e., high net load hours).

market unless there were at least two bid quantities included in that data. This data challenge also has the effect of some of the DRPs not having a MW-weighted average RT bid price calculated for them where there was no RT economic bid curve provided in the data. This could indicate that those DRPs, when awarded in the DA market, just reflected those awards as RT self-schedules and did not submit any additional economic offers in RT. It could also be the case that all the resources represented by those DRPs are designated as long-start resources and do not offer into the RT market unless they have received a DA schedule. However, without the complete dataset and RT self-scheduled megawatts, it is unclear what the underlying cause is. Thus, the Nexant Team excluded those hourly bids from the data analysis below.

Figure 7-1 shows the MW-weighted average bid prices of DRAM resources in DA and RT markets throughout the years. The chart shows that DRAM prices are generally above $750/MWh with the exception of 2020 RT prices. It should be noted that due to the RT data challenge discussed earlier, the RT MW weighted average bid prices in 2020 are based on a subset of the DRPs that had economic offers in the RT market included in the dataset, thus this anomaly could be a factor of data challenges.

The data also shows that in 2020, there seems to be a shift where the energy bid prices offered into the RT market is lower than the DA market bids. This is then followed by 2021 bid prices that have an interesting trend. Compared to 2020, the RT prices are higher but DA prices are lower, whereas compared to 2019 both the 2021 DA and RT prices are lower. This change in bidding behavior in recent years is seen throughout the results in this section and also supports the results seen in Section 7.3 where the scheduling rates increased year over year since 2019.

Figure 7-1: DRAM Day-ahead and Real-time MW-Weighted Average Bid Price



The following two tables show the MW-weighted average bid price from 2018 to 2021 by DRP. Table 7-1 includes the DA prices and Table 7-2 includes the RT prices. While the bidding behavior varies quite a bit by DRP, *[REDACTED]*.

Table 7-1: Day-ahead MW Weighted Average Bid Price by DRP

Demand Response Provider	2018		2019		2020		2021	
	Bid Price ($/MWh)	Total MWs Bid	Bid Price ($/MWh)	Total MWs Bid	Bid Price ($/MWh)	Total MWs Bid	Bid Price ($/MWh)	Total MWs Bid
[REDACTED]	*[REDACTED]*		*[REDACTED]*		*[REDACTED]*		*[REDACTED]*	
[REDACTED]								
[REDACTED]								
[REDACTED]								
[REDACTED]								
[REDACTED]								
[REDACTED]								
[REDACTED]								
[REDACTED]								
[REDACTED]								
[REDACTED]								

Table 7-2: Real-time MW-Weighted Average Bid Price by DRP

Demand Response Provider	2018		2019		2020		2021	
	Bid Price ($/MWh)	Total MWs Bid	Bid Price ($/MWh)	Total MWs Bid	Bid Price ($/MWh)	Total MWs Bid	Bid Price ($/MWh)	Total MWs Bid
[REDACTED]	*[REDACTED]*		*[REDACTED]*		*[REDACTED]*		*[REDACTED]*	
[REDACTED]								
[REDACTED]								
[REDACTED]								
[REDACTED]								
[REDACTED]								
[REDACTED]								
[REDACTED]								
[REDACTED]								
[REDACTED]								
[REDACTED]								

Figure 7-2 is intended to provide a visual sense of the dispersion of DRAM resource offer prices compared to that of other resource types. This is then followed by Figure 7-3 which shows the MW-weighted average bid price comparison between DRAM and other participating resources in 2020 and 2021. IOU DR and DRAM resources tend to have similar offer prices but far exceed that of peaker plants and IFOM storage resources. Recall that the offer prices are only representative of resources whereby the data included an economic bid curve for the resource in a given trading hour for the respective market (DA or RT).

Figure 7-2: Dispersion of Average Bid Prices by Resource Type

Figure 7-3: MW-Weighted Average Bid Price Comparison Across Resource Types

[REDACTED]

This next set of metrics evaluate the distribution of offer prices by DRAM resources. This is shown for DA and RT separately and both at an aggregate level and also by DRP.

As shown in Figure 7-4 and Figure 7-5, the $900-$1,000/MWh bid price category has the highest percentage of megawatts each year for both the DA and RT markets, with the exception of the 2020 RT market. This is followed by megawatts being offered in at the $100-$500/MWh range.

Also of note is the shift seen in offer prices in the RT market starting in 2020. The megawatts seem to be offered in at prices that are more distributed across the bid price categories. In other words, when compared to prior years' RT markets the concentration of MWs are not only in the $250-$500/MWh and $900-$1,000/MWh categories; there seems to be an increase in the percentage of MWs offered in at the $100-$250/MWh and $500-$750/MWh range as well. Part of this may be the data challenge where the Nexant Team was unable to confidently determine if some of the RT scheduled megawatts were self-scheduled (which would lower the overall average when taken into consideration and shift the distribution to the left) or if it is just a matter of incomplete data.

Figure 7-4: Percentage of DRAM Day-ahead Bid in MWs by Price Category

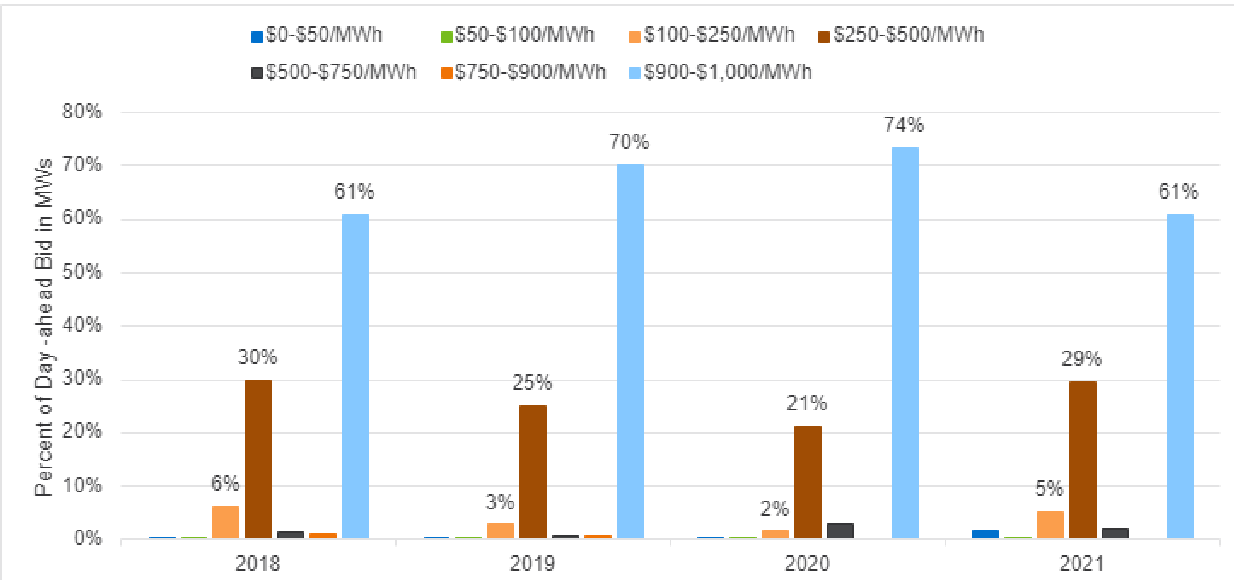


Figure 7-5: Percentage of DRAM Real-time Bid in MWs by Price Category

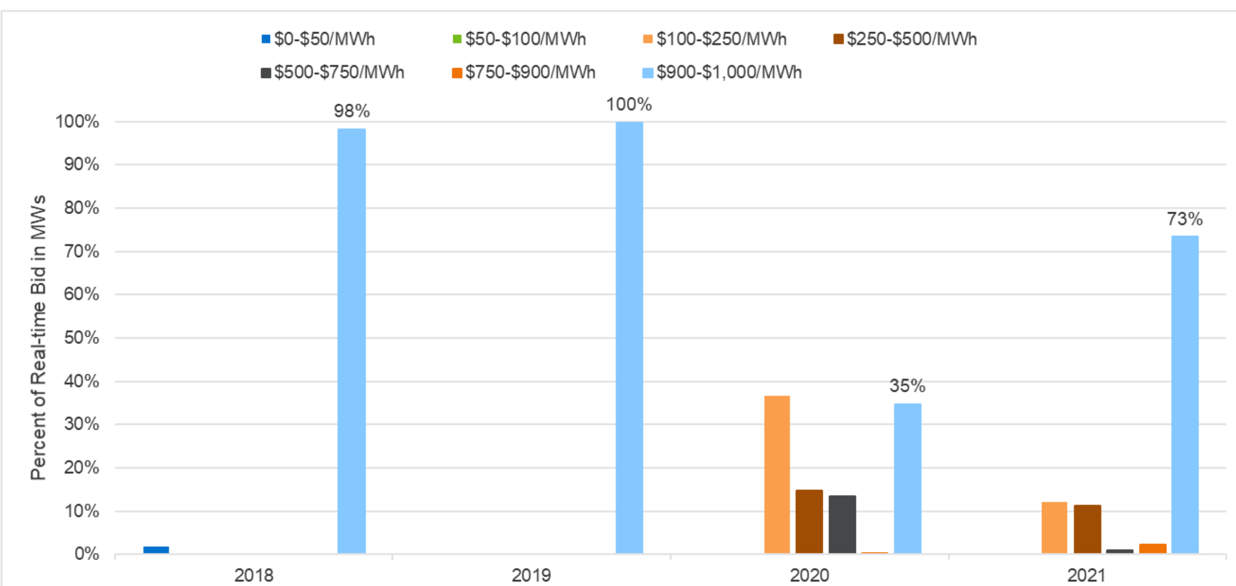


Table 7-3 and Table 7-4 below show the breakdown of DA and RT bids in megawatts by price category and DRP. It should be noted that if a DRP does not have a metric provided, that does not necessarily mean they did not offer into that market; it simply indicates that the data set provided did not include the bid curves for the resources under that DRP or that the Nexant Team was unable to map resource IDs to the DRPs.

Table 7-3: Percentage of Day-ahead Bid in MWs by Price Bin and DRP

Price Bid Category	*[REDACTED]*
2018	
[REDACTED]	*[REDACTED]*
[REDACTED]	*[REDACTED]*
[REDACTED]	*[REDACTED]*
[REDACTED]	*[REDACTED]*
[REDACTED]	*[REDACTED]*
[REDACTED]	*[REDACTED]*
2019	
[REDACTED]	*[REDACTED]*
[REDACTED]	*[REDACTED]*
[REDACTED]	*[REDACTED]*
[REDACTED]	*[REDACTED]*
[REDACTED]	*[REDACTED]*
[REDACTED]	*[REDACTED]*
2020	
[REDACTED]	*[REDACTED]*
[REDACTED]	*[REDACTED]*
[REDACTED]	*[REDACTED]*
[REDACTED]	*[REDACTED]*
[REDACTED]	*[REDACTED]*
[REDACTED]	*[REDACTED]*
2021	
[REDACTED]	*[REDACTED]*
[REDACTED]	*[REDACTED]*
[REDACTED]	*[REDACTED]*
[REDACTED]	*[REDACTED]*
[REDACTED]	*[REDACTED]*
[REDACTED]	*[REDACTED]*

Table 7-4: Percentage of DRAM Real-time Bid in MWs by Price Category and DRP

Price Bid Category	*[REDACTED]*
2018	
[REDACTED]	*[REDACTED]*
[REDACTED]	*[REDACTED]*
[REDACTED]	*[REDACTED]*
[REDACTED]	*[REDACTED]*
[REDACTED]	*[REDACTED]*
[REDACTED]	*[REDACTED]*
2019	
[REDACTED]	*[REDACTED]*
[REDACTED]	*[REDACTED]*
[REDACTED]	*[REDACTED]*
[REDACTED]	*[REDACTED]*
[REDACTED]	*[REDACTED]*
[REDACTED]	*[REDACTED]*
2020	
[REDACTED]	*[REDACTED]*
[REDACTED]	*[REDACTED]*
[REDACTED]	*[REDACTED]*
[REDACTED]	*[REDACTED]*
[REDACTED]	*[REDACTED]*
[REDACTED]	*[REDACTED]*
2021	
[REDACTED]	*[REDACTED]*
[REDACTED]	*[REDACTED]*
[REDACTED]	*[REDACTED]*
[REDACTED]	*[REDACTED]*
[REDACTED]	*[REDACTED]*
[REDACTED]	*[REDACTED]*

Table 7-5 and Figure 7-6 summarize the changes in bidding behavior between the DA and RT market. Each line in Figure 7-6 is the cumulative distribution of bid prices. For example, all the RT offers in 2019 were offered in at prices between $750/MWh and $1,000/MWh whereas the megawatts offered in the RT market for 2021 start being offered in at prices around $100/MWh. This figure shows that (1) 2021 DA offer prices are slightly lower than 2019 and (2) some of the 2021 DA offer prices are reduced in RT.

Figure 7-6: DRAM 2019 vs 2021 Cumulative Percentage of Bid in MWs by Bid Price Category

Table 7-5 shows the changes in offer prices between the DA and RT markets between DRAM and IOU DR resources. The Nexant Team first calculated the MW-weighted average bid price for each resource in each hour for both the DA and RT markets. Then each resource hour was categorized as having a higher or lower MW-weighted average RT bid when compared to the DA MW-weighted average bid price for the same resource and same operating hour. The table summarizes the percentage of resource bids that were increased in RT versus the percentage that was either left unchanged or decreased in RT when compared to DA. Only resource hours that had complete economic bid curves in the data for both the DA and RT markets were included in the analysis, so this table does not include all the resources that were included in Figure 7-1. The table also includes the average change in offer price between the two markets.

Table 7-5: Change Between Day-ahead and Real-time Offer Prices

Year	IOU DR		DRAM	
	Increased Real-time Bid	$/MWh Change in Offer Price	Increased Real-time Bid	$/MWh Change in Offer Price
2018	*[REDACTED]*		*[REDACTED]*	
2019				
2020				
2021				
Year	**Lowered or Unchanged Real-time Bid**	**$/MWh Change in Offer Price**	**Lowered or Unchanged Real-time Bid**	**$/MWh Change in Offer Price**
2018	*[REDACTED]*		*[REDACTED]*	
2019				
2020				
2021				

7.3 Scheduling Rate

As noted earlier, the scheduling rate metric seeks to test a given resource's ability in getting its available capacity scheduled in the market. The scheduling rate measures the awarded energy schedule relative to the total quantity bid in the market.

The scheduling rate analysis described above is evaluated for several different periods of interest including (1) all hours, (2) the availability assessment hours (AAHs), and (3) the availability assessment hours during the July – September months. The availability assessment hours is a period of interest because DRAM resources have a Must-Offer Obligation to bid their capacity into the day-ahead (DA) and real-time (RT) during those hours; particularly, the AAHs during Q3 are also of interest as that is when the highest system needs occur and thus one would anticipate a higher utilization of DRAM resources.

The scheduling rates below are first presented for DRAM resources only, focusing on comparisons between the various time periods and between the DA and RT markets. Then comparisons of scheduling rates among the various resource types are presented next.

Figure 7-7 below shows the DRAM DA scheduling rates by year for each of the periods of interest. Table 7-6 includes the total DA bid in MWs to provide more context around the overall magnitude of the scheduling rates. Similar metrics are provided in Figure 7-8 and Table 7-7 reflecting the RT market scheduling rates.

Each period of interest represented in Figure 7-7 and Figure 7-8 below are shown in order of ascending system need. Thus, within each year it is also important to note that as the time period narrows in on the AAH hours, the scheduling rates also increase with the exception of

2018 and 2019 in RT.[43] This seems to indicate that the DRAM resources are more effective in getting the capacity scheduled when they are most needed.

Figure 7-7: DRAM Day-ahead Scheduling Rate by Time Period

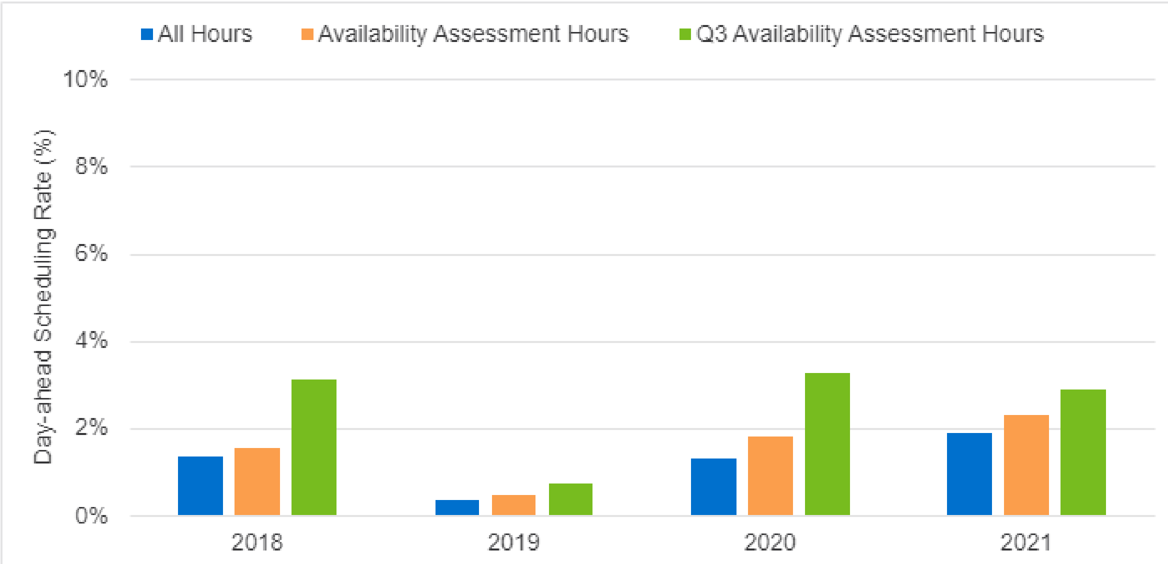


Table 7-6: DRAM Day-ahead Bid in Megawatts by Varying Time Horizons

Total Day-ahead Bid in MWs			
Year	**All Hours**	**AAH**	**Q3 AAH**
2018	109,615	81,794	33,704
2019	513,823	406,042	110,501
2020	328,788	239,500	97,892
2021	293,798	230,751	86,098

43 This is likely due to incomplete CAISO bid data set for 2018 and 2019, thus understating the scheduling rates in those years.

Figure 7-8: DRAM Real-time Scheduling Rates by Varying Time Horizons

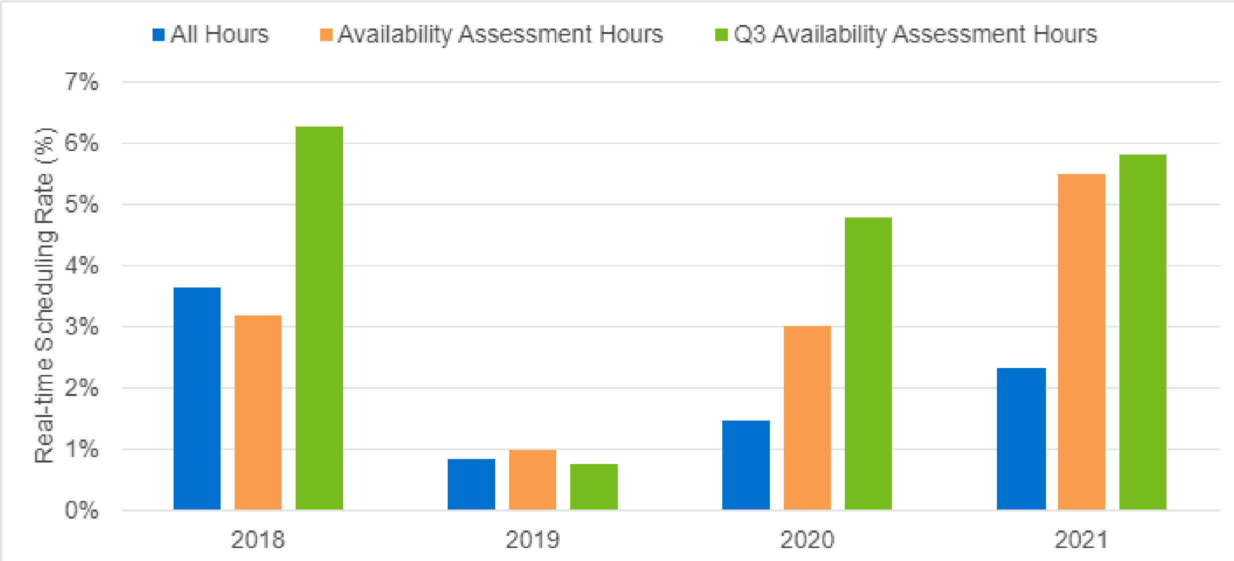


Table 7-7: DRAM Real-time Bid in Megawatts by Varying Time Horizons

Total Real-time Economically Offered MWhs			
Year	All Hours	AAH	Q3 AAH
2018	83,801	68,611	29,259
2019	434,074	357,191	99,052
2020	332,722	149,829	55,992
2021	228,865	96,214	47,851

Overall, the scheduling rate of DRAM resources has been increasing year by year since 2019 in both the DA and RT markets. There are a few factors that are likely contributing to the higher scheduling rates. The bidding behavior of DRAM resources, shown in Section 7.2, seems to be leading to higher scheduling rates in both the DA and RT markets. In recent years (2020 and 2021) the DRPs seems to be offering their capacity into the DA and RT markets at lower prices compared to previous years. Additionally, tighter supply conditions in the CAISO market may also be contributing to higher scheduling rates. Put differently, we may have seen higher scheduling rates absent lower energy offers simply because there is less supply on the system and the market is having to utilize the higher priced resources more frequently to meet load than would have been the case a couple years prior. It is also important to note that the Commission set much stricter dispatch requirements for 2020 and 2021 DRAM. These requirements mandate a certain level of dispatch which also could be contributing to lowers bids and higher scheduling rates. We explain this further in the discussion section.

Table 7-8 shows the range of CAISO energy prices in both the DA and RT markets by year. The Nexant Team analyzed the nodal energy prices available via the CAISO bid data set during the Availability Assessment Hours (AAH); this includes energy prices when the resources were scheduled as well as when they were not. The average energy prices increase in 2020 and 2021 compared to 2019, indicating that the system was facing tighter supply conditions and needing to dispatch resources further up the bid stack more frequently. This does indicate that the tight supply conditions may also be contributing to higher scheduling rates, but absent running market simulations, one cannot clearly differentiate between the two contributing factors (i.e., lower offer prices and tight supply conditions).

Table 7-8: Energy Price Range during Availability Assessment Hours

Year	Day-ahead			Real-time (5-minute)		
	Min	Avg	Max	Min	Avg	Max
2018	($49.32)	$86.29	$1,009.79	($58.29)	$65.56	$1,000.36
2019	($25.42)	$53.79	$1,027.82	($237.72)	$53.68	$1,113.97
2020	($5.94)	$76.02	$1,564.70	($337.63)	$51.10	$1,263.78
2021	($6.16)	$83.03	$1,006.88	($217.76)	$64.50	$1,080.58

The comparison of DA and RT scheduling rates by DRP is shown in Table 7-9 below. The scheduling rate by DRP does vary quite a bit with some DRPs having higher scheduling rates than others in both markets and across all years. This is also likely a factor of how each DRP is offering their respective capacity in the market as discussed below in Section 7.3.

Table 7-9: Day-ahead and Real-time Scheduling Rates by DRP

<table>
<tr><th rowspan="2">Demand Response Provider</th><th colspan="2">2018</th><th colspan="2">2019</th><th colspan="2">2020</th><th colspan="2">2021</th></tr>
<tr><th>Day-ahead</th><th>Real-time</th><th>Day-ahead</th><th>Real-time</th><th>Day-ahead</th><th>Real-time</th><th>Day-ahead</th><th>Real-time</th></tr>
<tr><td>[REDACTED]</td><td colspan="2" rowspan="10">[REDACTED]</td><td colspan="2" rowspan="10">[REDACTED]</td><td colspan="2" rowspan="10">[REDACTED]</td><td colspan="2" rowspan="10">[REDACTED]</td></tr>
<tr><td>[REDACTED]</td></tr>
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<tr><td>[REDACTED]</td></tr>
<tr><td>[REDACTED]</td></tr>
<tr><td>[REDACTED]</td></tr>
</table>

Another means of evaluating how competitively DRAM resources are offered into the wholesale market is by comparing DRAM scheduling rates to other similarly situated resource types. Below, the Nexant Team first presents a comparison of DRAM to IOU DR Programs' scheduling rates. This is then followed by comparing scheduling rates across additional resource types – specifically a select set of peaker plants and storage resources. The following charts compare the scheduling rates between DRAM resources and a select set of IOU DR programs during all hours and the Availability Assessment Hours.[44]

As shown in Figure 7-**9** and Figure 7-10, both DRAM and IOU DR programs have overall higher scheduling rates during AAHs compared to all hours. Figure 7-10 below shows that DRAM resources have increased scheduling rates in 2020 and 2021 when compared to 2019. Additionally, DRAM resources seem to be scheduled at similar rates of IOU DR programs in 2021. However, IOU DR programs seem to be more active in getting the capacity scheduled in the DA market compared to DRAM resources indicating that the IOU DR programs are offered in at prices that are more “competitive” than DRAM resources in that market. It should be noted that for both DRAM and IOU DR programs, the RT scheduling rates may be understated as those only include hours for which RT economic bid curves were available. Thus, to the extent a resource was scheduled in the DA and then had the DA schedule reflected in RT as a self-schedule, the RT metric may not pick that up. Therefore, the RT scheduling rates can be considered a lower bound.

[44] The Nexant TEAM was only able to include IOU DR program resources for which the resources were identified and provided to the Team. Thus, not all resources in the IOU DR programs are included in these metrics. Also note that RDRRs are excluded from the analysis.

Figure 7-9: DRAM vs IOU DR Scheduling Rates During, All Hours

[REDACTED]

Figure 7-10: DRAM vs IOU Scheduling Rates During Availability Assessment Hours

[REDACTED]

The results in Table 7-10 and Table 7-11 below are the same scheduling rates as discussed above and are based on the same data set but compare DRAM resources to additional resource types.

While the data does show that the scheduling rates of DRAM resources increase year over year in both the DA and RT markets, they still generally fall below the scheduling rates of the other resource types. In 2021 the DRAM resources do have a higher scheduling rate than the IOU DR programs for both hour categories. *[REDACTED]*. Resources that receive a DA schedule have the option to either (1) re-bid into the RT market at economic prices or (2) allow their DA schedule to essentially flow into the RT. The second option then looks like a self-schedule in the RT market equal to the DA schedule from a data perspective. Thus, to the extent some of the resources allowed their DA schedule to be self-scheduled in RT, the RT scheduling rates would increase.

[REDACTED].

IFOM storage resources[45] and peaker plants have higher scheduling rates than both IOU DR and DRAM resources. *[REDACTED].*

[REDACTED]. However, the CAISO market also considers start up and minimum load costs for some resource types (such as peakers), along with the energy offers, from resources that submit such costs into the market offers. Thus, even though a resource may have a relatively low energy offer, that is not the only cost evaluated when the market is determining which resources to commit and dispatch for energy. *[REDACTED].* The dataset provided to the Nexant Team did not include start up and commitment cost offers.

Storage resources, in general, have been providing ancillary services (primarily regulation up and down). When a storage resource is providing both energy and ancillary services, the market will ensure the energy schedule plus any awarded upward ancillary service does not exceed the maximum output of the resource, while also taking into account state-of-charge.[46] For example, if a 10 MW storage resource is awarded 7 MW of regulation up, the market will only schedule it up to 3 MWh of discharge energy (assuming sufficient state-of-charge to support both awards). This results in a lower overall scheduling rate for energy because the resource is being utilized to provide another product. The dataset provided did not provide include any ancillary service awards, thus the Nexant Team was unable to confirm what portion of the storage resource capacity included in this analysis was awarded ancillary services rather than energy.

Table 7-10: Day-ahead Scheduling Rate by Resource Type

Resource Type	2018		2019		2020		2021	
	All Hours	Q3 AAH	All Hours	Q3 AAH	All Hours	Q3 AAH	All Hours	Q3 AAH
IOU DR	*[REDACTED]*		*[REDACTED]*		*[REDACTED]*		*[REDACTED]*	
DRAM								
Peakers								
Storage								

45 *[REDACTED].*

46 This is true for all resources offering in both energy and ancillary services.

Table 7-11: Real-time Scheduling Rate by Resource Type

Resource Type	2018		2019		2020		2021	
	All Hours	Q3 AAH	All Hours	Q3 AAH	All Hours	Q3 AAH	All Hours	Q3 AAH
IOU DR	*[REDACTED]*		*[REDACTED]*		*[REDACTED]*		*[REDACTED]*	
DRAM								
Peakers								
Storage								

7.4 Scheduling Effectiveness

The scheduling effectiveness metric seeks to test a given resource's effectiveness in getting its available capacity scheduled in the market during the 120 hours of highest CAISO system need. In this section, we present the scheduling effectiveness during the top 120 net load hours in each year from 2019-2021.

As such, the scheduling effectiveness is essentially the scheduling rate metric but narrowing in on the hours with highest system needs – specifically for this analysis, the top 120 net load hours in each year. Overall, the Nexant Team's evaluation below shows that DRAM resources, when scheduled by the CAISO market, are getting scheduled at higher rates during the top 120 net load hours than when compared to all hours. Additionally, the scheduling effectiveness in the RT market over the last two years of this evaluation have significantly increased from prior years.

Table 7-12 provides the scheduling effectiveness of DRAM resources in both the DA and RT markets. The table also provides the scheduling rates for comparison purposes. The scheduling of DRAM resources during the top 120 net load hours is significantly higher in both the DA and RT markets when compared to the scheduling rate, especially in 2020 and 2021. This would be expected as the CAISO market tends to have to dispatch resources further up the supply curve (i.e., resources offered in at higher prices) during those hours when compared to all hours of the trading day.

Table 7-13 then provides the scheduling effectiveness by DRP for both the DA and RT markets. Here again, the scheduling effectiveness improves in the last two years (2020 and 2021) for nearly all DRPs.

Table 7-12: Day-ahead and Real-time Scheduling Effectiveness, by Year

Year	Scheduling Effectiveness		Scheduling Rate	
	Day-ahead	Real-time	Day-ahead	Real-time
2018	9%	9%	1%	4%
2019	2%	3%	0%	1%
2020	13%	22%	1%	1%
2021	7%	16%	2%	2%

Table 7-13: Day-ahead and Real-time Scheduling Effectiveness, by DRP

DRP	2018		2019		2020		2021	
	Day-ahead	Real-time	Day-ahead	Real-time	Day-ahead	Real-time	Day-ahead	Real-time
[REDACTED]	*[REDACTED]*		*[REDACTED]*		*[REDACTED]*		*[REDACTED]*	
[REDACTED]								
[REDACTED]								
[REDACTED]								
[REDACTED]								
[REDACTED]								
[REDACTED]								
[REDACTED]								
[REDACTED]								
[REDACTED]								

From a market perspective, seeing a higher scheduling rate from DRAM resources during the top 120 net load hours (referred to here as scheduling effectiveness) makes sense even given the offer prices. Net load is defined as load minus wind and solar generation. Thus, the top 120 net load hours represent the hours during the year where there is the highest level of load that needs to be met by resources other than wind and solar. Energy prices generally follow the net load curve. In other words, as the net load increases so do the energy prices. Therefore, it is more likely that the prices will reach levels that make it economic for the market to dispatch DRAM resources during the higher net load hour periods, resulting in higher scheduling rates, when compared to other time periods.

7.5 Discussion

It is very challenging to assess the competitiveness of the demand response wholesale energy bids in the absence of a formulaic approach (like for gas-fired resources) or a common understanding of the DR marginal energy costs. While MW-weighted annual average bid prices have generally stayed above $750/MWh in both the DA and RT markets, the proportion of RT bids at prices below the cap increased starting in 2020, resulting in a lower weighted average bid price. In addition, there has been an upward trend in scheduling rates and scheduling effectiveness starting in 2019.

There could be a few factors contributing to the lower offer prices, higher scheduling rates, and higher scheduling effectiveness observed in the later years:

- The new contractual obligation starting in 2020[47] and the additional minimum dispatch requirements for 2021[48] may be contributing to DRPs bidding at lower prices to fulfill dispatch requirements.

[47] D.19-07-009 and D.19-12-040 Appendix B

[48] D.19-12-040 Appendix C

- The CAISO is facing extremely tight supply conditions overall, thus the market may be relying on higher priced resource types such as DRAM resources more frequently simply due to the shortage of capacity on the system.

While we do observe a downward trend in DRAM prices in the later years, when comparing DRAM to other resource types, DRAM resources still seem to offer at price points that far exceed peaker plants and storage resources. Additionally, the offer prices far exceed the bid floor generated by the CAISO's net benefits test. The Net Benefits Test produces a price at which demand response resources are not able to bid below in the market; it sets a price floor for those resource types reflecting the fact that the market should only be dispatching this unique set of resources when prices reach a certain threshold. The threshold is supposed to represent the point at which the benefits to the market equal the cost of customers having to forego energy.

It should also be noted that there are other resource-specific factors in the CAISO's wholesale energy market, besides the energy bid curve prices, that can impact the scheduling rate and effectiveness of a resource. When making dispatch decisions, the CAISO market also considers commitment costs and physical characteristics of the resource. There are two main factors that may be impacting DRAM resources –start up time and commitment costs.

Regarding start up time, resources that are considered long-start resources can only be committed by the DA market. If a long-start resource is not committed and dispatched in the DA market, the RT market is unable to access its capacity/energy. Thus, any DRAM resource designated as a long-start resource which bids itself out of the market in the DA time frame has zero probability of being dispatched in the RT market. *[REDACTED].*[49]

Regarding commitment costs, a resource can specify a certain hourly cost associated with dispatching the resource (minimum load costs) as well as a minimum amount of time the resource must remain on before getting shut down. Resources can also specify a certain cost per commitment decision, referred to as a start-up cost. For example, if a resource has a minimum run time of two hours, minimum load cost of $1,000/hr, and a $5,000/start start-up cost, the market knows if it commits the resource, (1) it will incur the $5,000 start up cost, (2) it must keep it online for at least two hours, and (3) during each hour it is kept online, it will incur the $1,000/hr cost in addition to any costs associated with dispatching the resource for additional energy above its minimum operating point. These costs are considered by the market and can impact the economics of the resource being dispatched. The available CAISO Masterfile data does show that *[REDACTED]* has non-zero minimum load costs registered. *[REDACTED].* It should be noted that just because a resource has a non-zero minimum load cost registered in Masterfile does not mean it's being offered into the market at a non-zero price. The Nexant Team would need to evaluate the commitment cost offers submitted alongside the energy bid curves to confirm. That bid data was not available at the time of the evaluation.

[49] This is based on the assumption that the PGA_NAME and SC_ID field in Masterfile is an accurate representation of the DRPs.

While DRAM and IOU DR scheduling rates are somewhat similar (with IOU DR having higher DA scheduling rates), when compared to other resource types that are primarily used by the CAISO market during the higher system need periods, the DRAM resources tend to have much lower scheduling rates and scheduling effectiveness. This is especially true when comparing DRAM resource scheduling rates and scheduling effectiveness to storage and gas-fired peaker plants. The overall low scheduling rates and scheduling effectiveness also strongly correlate with higher wholesale energy offers, as discussed in the prior sections.

Looking at DRAM overall, the scheduling effectiveness tends to be higher than the scheduling rates. This makes intuitive sense as the scheduling effectiveness is the same metric as the scheduling rate but narrowed in on the hours of highest system need – specifically the top 120 net load hours of each year. This trend indicates that the DRAM resources are being committed and dispatched by the market more effectively during the time periods when one would anticipate such resources being needed to serve net load. In other words, the utilization of the DRAM resources aligns with when they are of higher value to the market.

At the DRP level, there is quite a bit of variability between the DRPs in regard to bidding behavior, scheduling rates and scheduling effectiveness. And as one would expect, the DRPs that offer in at lower rates are those that have the higher scheduling rates and scheduling effectiveness.

[REDACTED].

8 Criterion 5: Did DRPs Meet Their Contractual Obligations?

The purpose of Criterion 5 (per D. 16-09-056) was to assess whether DRPs met their contractual obligations. In this evaluation, the Nexant Team assesses three types of contract compliance, which are presented in this report section as follows:

- Section 8.1 compares Contracted Capacity, Supply Plan Capacity, and Demonstrated Capacity. DRPs' contract compliance was measured by assessing the ability of the DRPs to align Supply Plan and Demonstrated Capacity values with Contracted Capacity.
- Section 8.2 assesses Must Offer Obligation (MOO) compliance by comparing total DA market bids to each DRP's MOO.
- Section 8.3 presents how well the DRPs met the minimum energy requirement in the 2021 DRAM contracts.

8.1 Contracted Capacity, Qualifying Capacity and Demonstrated Capacity Comparison

Contracted Capacity is defined as the amount of capacity a DRP has agreed to provide to the IOU for each day of the respective showing month within the contracted term.

Qualifying Capacity (QC) reflects the amount of total capacity a DRP has aggregated and showed on the monthly supply plan. It is indicative of a DRP's ability to enroll enough participants to provide the aggregated load reduction it promised in its contract with the IOU. Month-ahead supply plans must be submitted to the IOUs sixty days prior to each delivery month.

Demonstrated Capacity (DC) is the amount of qualifying capacity the DRP was capable of delivering in each delivery month. This value is indicated to the IOUs through invoicing at the end of each delivery month and can be based on one three options with the below order:

1. **Demonstrated Capacity – Dispatch:** The results of a DC Dispatch during the applicable Showing Month, equal to the maximum hourly load reduction[50] calculated using the appropriate baseline method;

[50] For the Showing Month of August, the DC will equal the average hourly load reduction (of a min 2-hr dispatch) during a DC Dispatch, rather than the maximum hourly load reduction.

2. **Demonstrated Capacity – Test:** The results of a DC Test in the event, equal to the maximum hourly load reduction[51] during any hour of such DC Test calculated using the appropriate baseline method; or

3. **Demonstrated Capacity – MOO:** The average amount of capacity for each resource that the DRP bid into the applicable CAISO Markets during the AAH hours in the Showing Month (in compliance with the CAISO MOO).

The DRPs are required to demonstrate capacity based on an actual market dispatch or test and can only use their MOO for the purposes of DC invoicing if there has been no full dispatch or test of the resource in a given month.

The three IOUs provided contract and invoice data to the Nexant Team via templates developed by Energy Division. The submitted templates included monthly contracted capacities for each DRAM contract from 2018 to 2021. The IOUs also provided the month-ahead supply plans, which are the basis for the "Qualifying Capacity" values presented in the following figures. The IOUs provided complete DC invoice data through December 2021[52], split by capacity test, MOO, and market dispatch. These invoiced capacities are summed to represent the aggregate demonstrated capacity for a DRP over a given period.

DRP-level results are presented for the entire year, for the third quarter, and for the month of August of each year evaluated. Contracted, qualifying, and demonstrated capacity totals by resource were summed to the DRP total during the relevant time period, allowing for an analysis of the alignment of the DRPs' qualifying and demonstrated capacity compared to its aggregate contracted capacity. In 2018 and 2019 DRAM some DRPs' contracts were terminated and as a result, these contracts were not included in the analysis. *[REDACTED].*

8.1.1 Aggregate-Level Analysis

Figure 8-1 compares the annual contracted capacity, qualifying capacity, and the three types of demonstrated capacity (capacity test, MOO, and market dispatch) from 2018 to 2021. The blue bar represents the aggregate contracted capacity (MW) and the green bar represents aggregate qualifying capacity (MW). The stacked orange bar represents invoiced demonstrated capacities, which can either be from a market dispatch, a capacity test, or the resource's MOO. When the total demonstrated capacity is less than the qualifying capacity (the stacked orange bar is lower than the green bar), it indicates a deficiency in demonstrated capacity.

In 2018, the demonstrated capacity of the DRPs[53] was in close alignment (within about 97%) with both the contracted and qualifying capacity. DRP performance was slightly lower from 2019 to 2021. The demonstrated capacity was equal to 79% of the contracted capacity in 2019, 71% in 2020, and 65% in 2021. When looking at demonstrated capacity for the entire year, most of

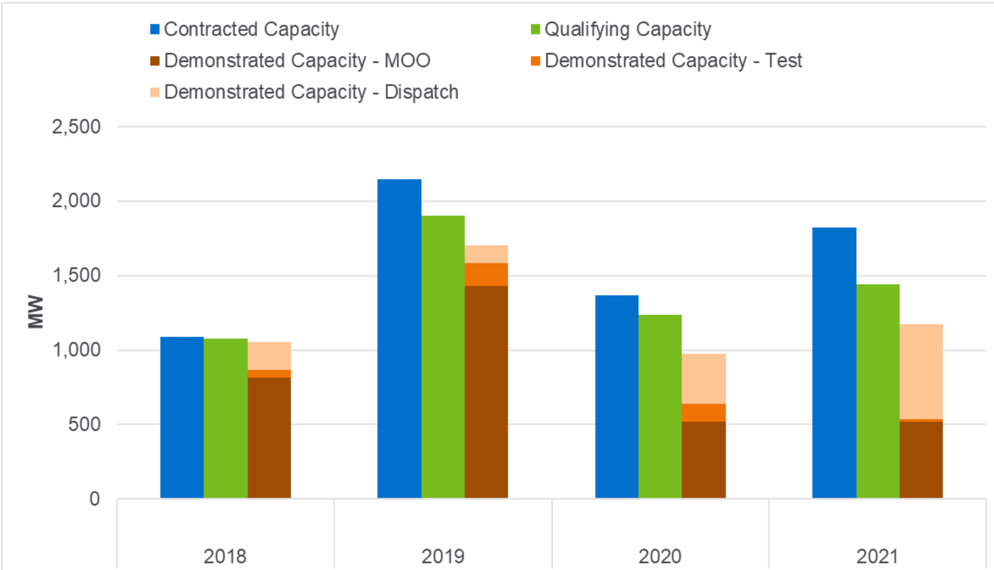
[51] For the Showing Month of August, the DC will equal the average hourly load reduction during any two consecutive hours, rather than the maximum hourly load reduction.

[52] *[REDACTED].*

[53] Results from 2018 and 2019 do not include *[REDACTED].*

the invoiced capacity is based on MOO. The MOO ranged from 77% of demonstrated capacity in 2018 to 84% in 2019, 53% in 2020, and 44% in 2021.

Figure 8-1: Annual Alignment of Contracted, Qualifying, and Demonstrated Capacity: All DRPs[54]



The data shows a lower number of MOO based DC invoices in 2020 and 2021 compared to prior years. This could be explained by the new requirements set in 2020 and 2021 DRAM pilots. Beginning in 2020 the Commission required that DC invoices must be based on a market dispatch or a capacity test for at least 50% of the contracted months during the contract term.[55] The Commission also added a new requirement effective 2021 for a minimum dispatch requirement in DRAM contracts.[56] As a result, the number of MOO based DC invoices decreased in 2020 and 2021 compared to prior years.

Figure 8-2 shows the aggregate third quarter (July through September) alignment between contracted, qualifying and demonstrated capacity for all DRPs in 2018, 2019, 2020 and 2021. Demonstrated capacity in Q3 is of interest as this is generally when the highest system needs occur and thus higher utilization of DRAM resources. In this period, the trend followed a similar pattern as in the annual figure. As shown in Figure 8-2, in the third quarter even more of the demonstrated capacity is provided by market dispatch compared to other quarters. This is because in addition to the two requirements mentioned above, all DRAM resources must be dispatched for a minimum of two hours in the month of August.

[54] *[REDACTED]* had not finalized their DC invoices as of March 2022. As a result, November 2021 was not included for *[REDACTED]* and October, November, and December 2021 were not included for *[REDACTED]*.

[55] D.19-07-009 and D.19-12-040 Appendix B

[56] D.19-12-040 Appendix C

Figure 8-2: Q3 Alignment of Contracted, Qualifying, and Demonstrated Capacity: All DRPs

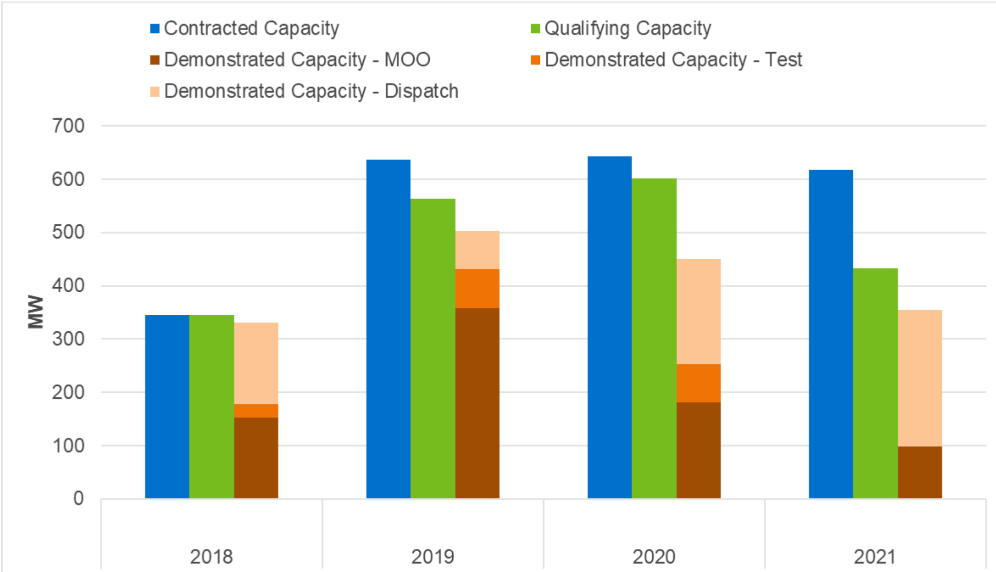
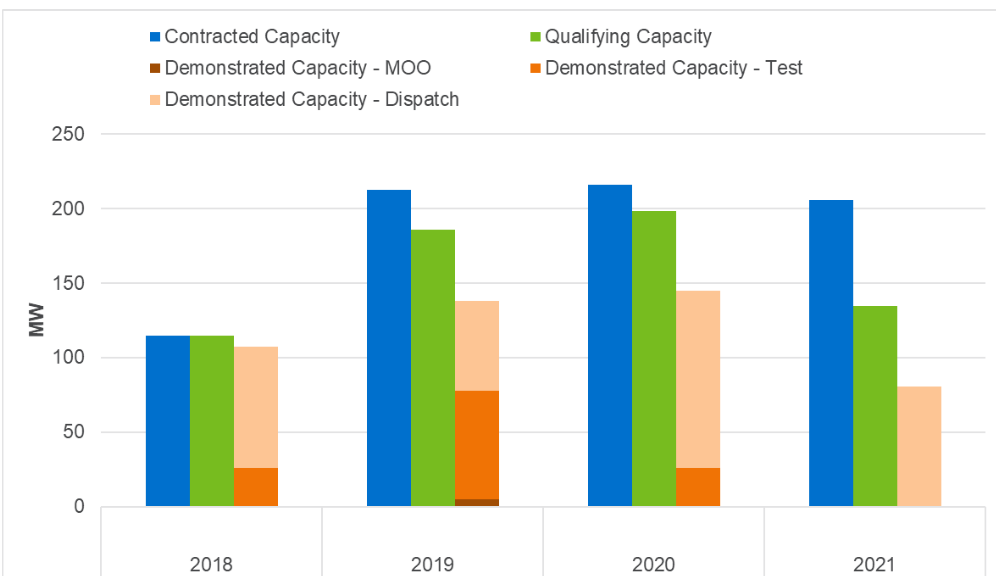


Figure 8-3 shows the aggregated performance data across all DRPs during the month of August from 2018 to 2021. Historically, August has been a system peaking month, particularly in 2020 when CAISO issued a Stage 3 Emergency for the first time in nearly twenty years. August is also the month in which DRPs are required to submit all their DC invoices based on actual market dispatch. General DRP performance trends follow a similar pattern in the month of August as the annual and Q3 levels. DRPs' alignment between the August contracted capacity and demonstrated capacity is highest in 2018 (about 94%) but falls to about 65% in August 2019 and 67% in August 2020, with the lowest alignment of 57% in August 2021.

Figure 8-3: August Alignment of Contracted, Qualifying, and Demonstrated Capacity: All DRPs



8.1.2 DRP-Level Analysis

Figure 8-4 through Figure 8-21 present the comparisons of contracted capacity, qualifying capacity, and demonstrated capacity for each DRP in 2018 through 2021. These comparisons are shown at both the annual level and for the month of August in each year the DRP participated in DRAM.

[REDACTED]

Figure 8-4 compares the alignment between *[REDACTED]*'s demonstrated capacity with their qualifying and contracted capacity. In *[REDACTED]*, *[REDACTED]*'s demonstrated capacity was 87% of their contracted capacity. In *[REDACTED]*, they provided 94% of their contracted capacity. *[REDACTED]*'s demonstrated capacity in *[REDACTED]* and *[REDACTED]* was almost wholly provided by their MOO, rather than tests and market dispatches. In *[REDACTED]*, *[REDACTED]*, and their demonstrated capacity was equal to 92% of their contracted capacity. *[REDACTED]*'s *[REDACTED]* demonstrated capacity was still mostly based on the MOO invoicing option, but also included a large share of market dispatches.

Figure 8-4: Annual Alignment of Contracted, Qualifying, and Demonstrated Capacity: *[REDACTED]*

[REDACTED]

[REDACTED]'s demonstrated capacity alignment compared to their contracted capacity was slightly lower in August *[REDACTED]* compared to their annual aggregate alignment.[57] In August *[REDACTED], [REDACTED]*'s demonstrated capacity was 81% of their contracted capacity. *[REDACTED]* overperformed in August *[REDACTED]*, demonstrating 123% of their contracted capacity, although it should be noted that their contracted capacity in August *[REDACTED]* was only *[REDACTED]* MW. *[REDACTED]* in August *[REDACTED]* and demonstrated 63% of their contracted capacity through capacity tests.

[57] *[REDACTED]*.

Figure 8-5: August Alignment of Contracted, Qualifying, and Demonstrated Capacity: *[REDACTED]*

[REDACTED]

[REDACTED]

Figure 8-6 presents the annual alignment of contracted, qualifying, and demonstrated capacity for *[REDACTED]*. They *[REDACTED]* and invoiced for about 70% of their contracted capacity. In *[REDACTED]*, *[REDACTED]*'s demonstrated capacity was equal to about 52% of their contracted capacity. In *[REDACTED]*, *[REDACTED]* demonstrated about 60% of their contracted capacity.

Figure 8-6: Annual Alignment of Contracted, Qualifying, and Demonstrated Capacity: *[REDACTED]*

[REDACTED]

Figure 8-7 presents *[REDACTED]* contract performance information for August *[REDACTED]*. In August *[REDACTED]*, test events provided about 42% of their contracted capacity, which is lower than their annual alignment of about 70% in *[REDACTED]*. In August *[REDACTED]* provided about 61% of their contracted capacity with both capacity tests and market dispatches, which is higher than their *[REDACTED]* annual alignment of 52%. Relative to the annual figures, a much larger portion of the demonstrated capacity in August is driven by capacity tests in *[REDACTED]* and market dispatches in *[REDACTED]*. This trend continues in *[REDACTED]*, where *[REDACTED]* demonstrated about 38% of their contracted capacity, wholly through market dispatches.

Figure 8-7: August Alignment of Contracted, Qualifying, and Demonstrated Capacity: *[REDACTED]*

[REDACTED]

[REDACTED]

Figure 8-8 shows the annual contract alignment for *[REDACTED]*. In *[REDACTED]* their demonstrated capacity was nearly 100% of their contracted capacity. Most of their *[REDACTED]* demonstrated capacity comes from their MOO, rather than from tests or market dispatches. In *[REDACTED]*, *[REDACTED]* demonstrated 97% of their contracted capacity. In contrast to the previous years, most of this capacity was driven by market dispatches. In *[REDACTED]*, *[REDACTED]* demonstrated about 79% of their contracted capacity, with the method evenly split between MOO and market dispatches.

Figure 8-8: Annual Alignment of Contracted, Qualifying, and Demonstrated Capacity: *[REDACTED]*

[REDACTED]

[REDACTED] also displayed high alignment in August. As shown Figure 8-9, *[REDACTED]'s* August *[REDACTED]* demonstrated capacity was 100% of its contracted capacity. In August *[REDACTED]* their demonstrated capacity was 95% of their contracted capacity. This demonstrated capacity was largely driven by MOO. In August *[REDACTED]*, *[REDACTED]* demonstrated 99% of their contracted capacity, through market dispatch. In August *[REDACTED]*, *[REDACTED]* demonstrated 19% of their contracted capacity through market dispatch.

Figure 8-9: August Alignment of Contracted, Qualifying, and Demonstrated Capacity: *[REDACTED]*

[REDACTED]

[REDACTED]

Figure 8-10 shows that in *[REDACTED]*, *[REDACTED]*'s demonstrated capacity was higher than their contracted capacity. In *[REDACTED]*, *[REDACTED]* had a similarly high alignment with their contracted capacity and demonstrated 98% of their contracted capacity (note their demonstrated capacity is higher than their qualifying capacity in *[REDACTED]*). In *[REDACTED]*, *[REDACTED]* demonstrated 86% of their contracted capacity; most of this capacity was achieved with market dispatches. *[REDACTED]* continued this trend of high alignment into *[REDACTED]* where they demonstrated 90% of their contracted capacity.

Figure 8-10: Annual Alignment of Contracted, Qualifying, and Demonstrated Capacity: *[REDACTED]*

[REDACTED]

[REDACTED] provided for all its August demonstrated capacity as a market dispatch. As shown in Figure 8-11, *[REDACTED]* market dispatches made up for 129% of their contracted capacity in August *[REDACTED]*. In August *[REDACTED], [REDACTED]* dispatched 85% of their contracted capacity, in August *[REDACTED]* they dispatched 91% of their contracted capacity, and in August *[REDACTED]* demonstrated 94% of their contracted capacity. Overall, *[REDACTED]* had high compliance with their contractual obligations.

Figure 8-11: August Alignment of Contracted, Qualifying, and Demonstrated Capacity: *[REDACTED]*

[REDACTED]

[REDACTED]

[REDACTED].

Figure 8-12: Annual Alignment of Contracted, Qualifying, and Demonstrated Capacity: *[REDACTED]*

[REDACTED]

[REDACTED].

Figure 8-13: August Alignment of Contracted, Qualifying, and Demonstrated Capacity: *[REDACTED]*

[REDACTED]

[REDACTED]

[REDACTED]. Figure 8-14 displays their aggregate contracted capacity alignment for the year of *[REDACTED]*. In *[REDACTED]*, *[REDACTED]* had 100% alignment between their contracted capacity and qualifying capacity, and their demonstrated capacity was 84% of their contracted capacity. In *[REDACTED]*, *[REDACTED]* demonstrated about 86% of their contracted capacity. *[REDACTED]*.

Figure 8-14: Annual Alignment of Contracted, Qualifying, and Demonstrated Capacity: *[REDACTED]*[58]

[REDACTED]

In August *[REDACTED]*, *[REDACTED]* had lower alignment between their contracted and demonstrated capacity. Figure 8-15 shows that *[REDACTED]*'s August *[REDACTED]* demonstrated capacity was 65% of their demonstrated capacity and was all provided through market dispatches. Alignment was slightly lower in August *[REDACTED]*, where *[REDACTED]* demonstrated about 32% of their contracted capacity.

Figure 8-15: August Alignment of Contracted, Qualifying, and Demonstrated Capacity: *[REDACTED]*

[REDACTED]

[58] *[REDACTED]*

[REDACTED]

Figure 8-4 shows the annual performance results for *[REDACTED]*. They performed well in *[REDACTED]* and demonstrated 96% of their contracted capacity, mostly through MOO. *[REDACTED]* only demonstrated about 35% of their contracted capacity in *[REDACTED]*.

Figure 8-16: Annual Alignment of Contracted, Qualifying, and Demonstrated Capacity: *[REDACTED]*

[REDACTED]

[REDACTED]'s contract compliance was slightly lower in August compared to their annual performance. As shown in Figure 8-17 in *[REDACTED]* demonstrated 54% of their August *[REDACTED]* contracted capacity. In August *[REDACTED]* they only demonstrated 10% of their contracted capacity. All of their August demonstrated capacity was achieved through capacity tests.

Figure 8-17: August Alignment of Contracted, Qualifying, and Demonstrated Capacity: *[REDACTED]*

[REDACTED]

[REDACTED]

Figure 8-18 shows the annual alignment for *[REDACTED]*. In *[REDACTED]*, *[REDACTED]*'s demonstrated capacity was equal to 94% of their contracted capacity. In *[REDACTED]* their demonstrated capacity fell slightly, accounting for 90% of their contracted capacity. *[REDACTED]* in *[REDACTED]* and demonstrated about 90% of their contracted capacity. *[REDACTED]*'s contract in *[REDACTED]* was *[REDACTED]* than *[REDACTED]*, although they only demonstrated about 47% of their contracted capacity. The Nexant Team did not receive all qualifying and demonstrated capacity information for *[REDACTED]*. In addition, *[REDACTED]*.

Figure 8-18: Annual Alignment of Contracted, Qualifying, and Demonstrated Capacity: *[REDACTED]*[59]

[REDACTED]

[REDACTED]'s demonstrated capacity alignment was slightly lower in the month of August than their annual average. Figure 8-19 shows that in August *[REDACTED]* and August *[REDACTED]*, *[REDACTED]* demonstrated about 68% of their contracted capacity, mostly through market dispatches. In August *[REDACTED]*, *[REDACTED]*'s demonstrated capacity was a bit higher at 73% of their contracted capacity and was all provided via market dispatch. However, as shown in Figure 8-24, *[REDACTED]*'s bids were nearly 2.3 times higher than QC values in August *[REDACTED]*, so actual dispatch performance relative to bid quantities was significantly lower. *[REDACTED]*'s performance was much lower in August *[REDACTED]*, where they only demonstrated 21% of their contracted capacity.

59 *[REDACTED]*

Figure 8-19: August Alignment of Contracted, Qualifying, and Demonstrated Capacity: *[REDACTED]*

[REDACTED]

[REDACTED]

Figure 8-20 displays the annual alignment of contracted capacity for *[REDACTED]*. In *[REDACTED]*, *[REDACTED]*'s demonstrated capacity was 71% of their contracted capacity and was largely comprised of market dispatches. *[REDACTED]*'s alignment in *[REDACTED]* was a bit lower, with demonstrated capacity totaling about 49% of their contracted capacity. *[REDACTED]*'s *[REDACTED]* demonstrated capacity was also largely comprised of market dispatches. *[REDACTED]*'s alignment was higher in *[REDACTED]*, where they demonstrated about 80% of their contracted capacity through market dispatches.

Figure 8-20: Annual Alignment of Contracted, Qualifying, and Demonstrated Capacity: *[REDACTED]*

[REDACTED]

[REDACTED]'s alignment was slightly lower in the month of August compared to their aggregate annual total. In August *[REDACTED]*, *[REDACTED]*'s demonstrated capacity was 49% of their contracted capacity. *[REDACTED]*'s demonstrated capacity was 41% of their

contracted capacity in August *[REDACTED]*. *[REDACTED]*'s alignment increased in *[REDACTED]*, where they demonstrated about 72% of their contracted capacity. *[REDACTED]*'s demonstrated capacity in August *[REDACTED]*, August *[REDACTED]*, and August *[REDACTED]* was wholly comprised of market dispatches.

Figure 8-21: August Alignment of Contracted, Qualifying, and Demonstrated Capacity: *[REDACTED]*

[REDACTED]

8.2 Day-Ahead Bids vs. Must Offer Obligation

Beginning with the 2020 DRAM, the DRPs were required to submit quarterly reports that indicated, among other information, the amount bid into the day-ahead (DA) market and the qualifying capacity per month. This qualifying capacity was used to determine the must offer obligation (MOO), or the amount that each DRP is required to bid into the DA market each month.[60] Relative MOO compliance can be determined via a proportion of the total capacity bid into the DA market for a given DRP and month, and the total MOO for that same DRP and month. This section uses data from 2020 and 2021 DRAM pilots.

8.2.1 Aggregate-Level Analysis

Figure 8-22 illustrates total MOO compliance for all DRPs that were required to submit quarterly reports as a part of DRAM evaluation activities. The values used to determine MOO compliance were sourced from the quarterly reports referenced above, so MOO compliance is somewhat dependent on the accuracy of the reporting by each DRP[61]. In all but two of the quarters evaluated, DRPs bid over 100% of the required amount determined by their qualifying capacities. DRPs bid exactly 100% of their required MOO capacity in the remaining two quarters. DRPs overbid the most during the third quarter of 2020. During this quarter, the total MOO for all DRPs was 62 GWh; however, DRPs bid over 66 GWh of DR into the DA market. At

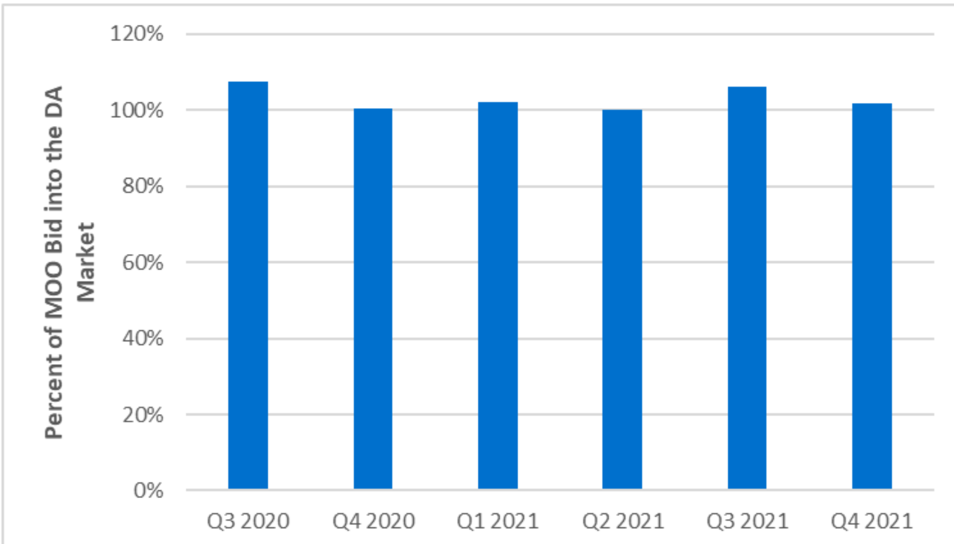
[60] MOO energy is calculated by multiplying the qualifying capacity by the number of AAH hours each month.

[61] While qualifying capacity values were able to be cross checked and verified against CAISO contracts, the accuracy of the amount bid into the DA market was entirely dependent on the accuracy of quarterly reports from DRPs and as such could not be verified by another source.

an aggregate quarterly level, DRPs are generally compliant with MOO requirements and bid at least their qualifying capacity into the DA market.

Bidding more than the MOO during the hotter summer months is reasonable, as there is more opportunity to win DR bids and thus earn more money from dispatching events. Additionally, it is possible that DRPs overbid into the market to ensure ample opportunity to meet or exceed performance goals (and not necessarily for MOO compliance).

Figure 8-22: Percent of Must Offer Obligation bid into the Day-Ahead Market: All DRPs



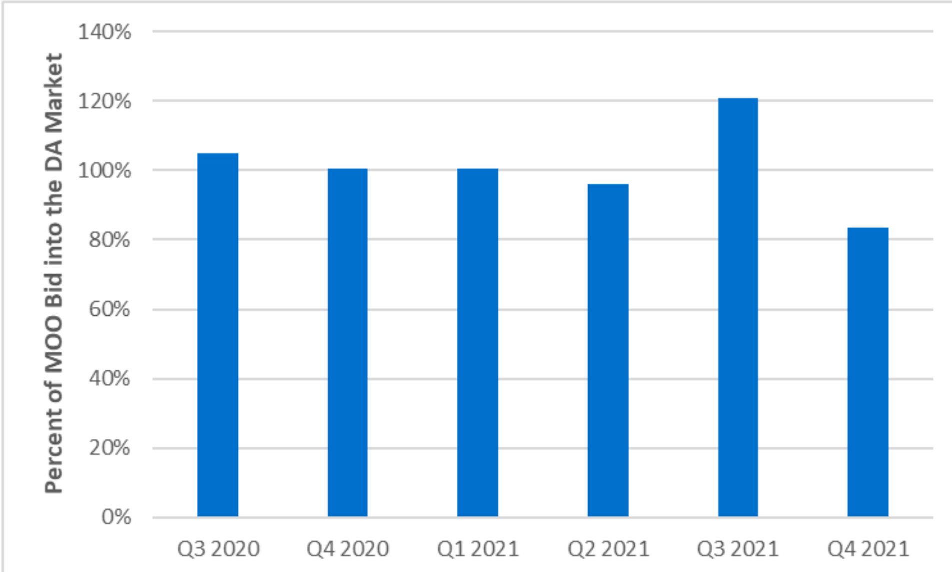
8.2.2 DRP-Level Analysis

MOO compliance varies between months at an aggregate level, as well as at a quarterly level for individual DRPs. The remainder of this section discusses each DRP's MOO compliance individually for Q3 2020 through Q4 2021 DRAM.

[REDACTED]

[REDACTED]'s MOO compliance is shown in Figure 8-23. *[REDACTED]* bid more than their MOO in four of the six quarters evaluated, and overbid the most during Q3 (i.e., the summer) of 2020 and 2021. *[REDACTED]* bid less than their required amount during Q2 and Q4 2021. Q2 MOO compliance was 97%, while Q4 compliance was amongst the lowest of all DRPs at 84%. The low compliance rate in Q4 is due in part to *[REDACTED]* not bidding all resource IDs on a given contract into the market during the quarter.

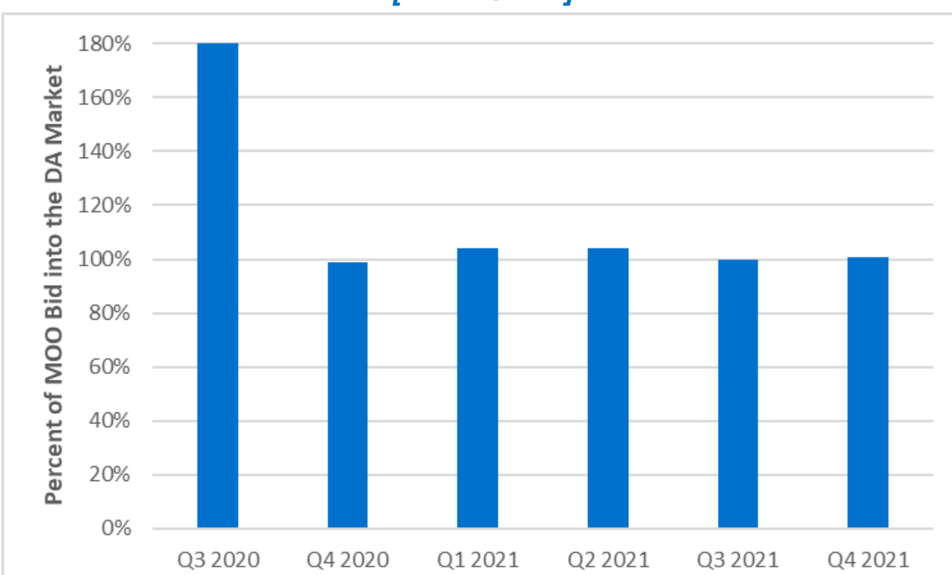
Figure 8-23: Percent of Must Offer Obligation bid into the Day-Ahead Market: *[REDACTED]*



[REDACTED]

As seen in Figure 8-24, *[REDACTED]* bid significantly more than what was required in Q3 2020, bidding close to double of their MOO over the summer. Bid compliance remained around 100% for the remainder of the evaluation period, ranging from 99% to 104% of what was required. *[REDACTED]* underbid in only one quarter of the evaluation period (Q4 2020).

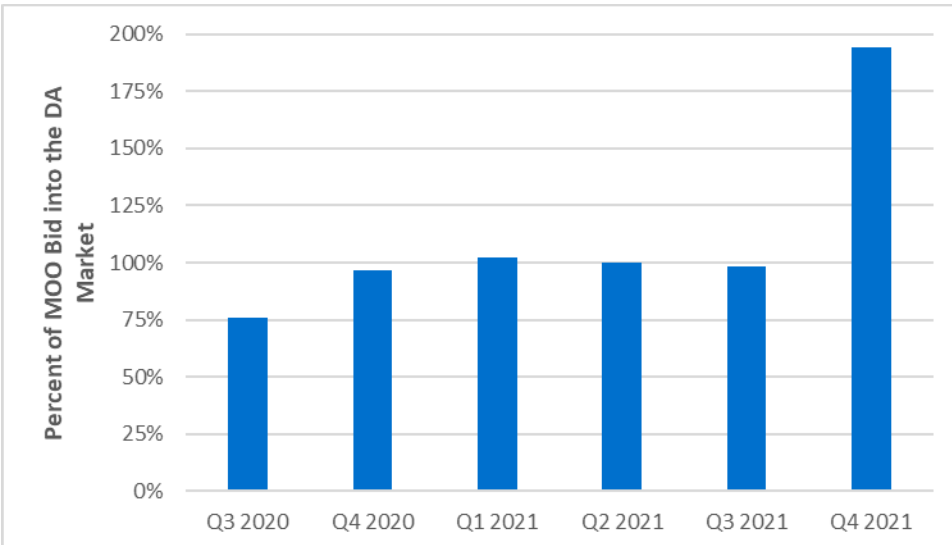
Figure 8-24: Percent of Must Offer Obligation bid into the Day-Ahead Market: *[REDACTED]*



[REDACTED]

Figure 8-25 shows the MOO compliance for *[REDACTED]*. *[REDACTED]* was the furthest outside of compliance out of all DRPs during Q3 2020, when they bid only 76% of their MOO into the DA market. Their qualifying capacity was adjusted during Q3 2020 and as a result *[REDACTED]* was able to come close to or meet the revised MOO for the remainder of the evaluation period. MOO compliance was 97% in Q4 2020, 98% in Q3 2021; and 100% during Q2 2021. *[REDACTED]* bid 194% of their MOO compliance into the market in Q4 2021; this was the highest amount that any DRP bid over their MOO in any quarter.

Figure 8-25: Percent of Must Offer Obligation bid into the Day-Ahead Market: *[REDACTED]*



[REDACTED]

[REDACTED]

Figure 8-26: Percent of Must Offer Obligation bid into the Day-Ahead Market: *[REDACTED]*

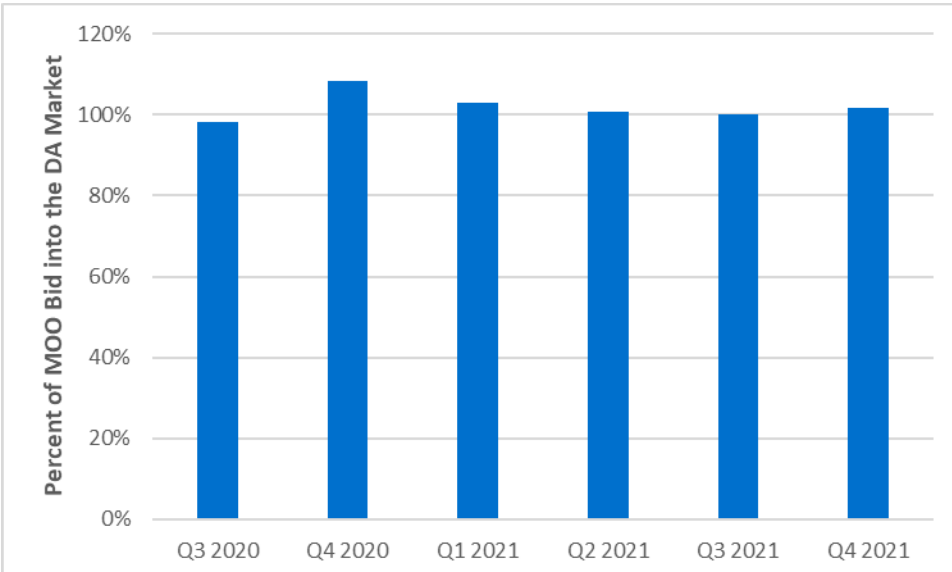
[REDACTED]

[REDACTED]

Figure 8-27 shows the MOO compliance for *[REDACTED]*. They generally bid at or slightly under 100% of their MOO over the course of the evaluation period, with bids ranging from 98%

to 108% of required capacity. Apart from *[REDACTED]*, *[REDACTED]* was the only other DRP to bid under their MOO obligation during Q3 of either year (i.e. the summer months), although to a lesser degree.

Figure 8-27: Percent of Must Offer Obligation bid into the Day-Ahead Market: *[REDACTED]*



[REDACTED]

Figure 8-28 shows the MOO compliance for *[REDACTED]*. *[REDACTED]*. *[REDACTED]* bid exactly 100% of their required capacity into the DA market each quarter except for Q2 2021, where they bid 104% of their MOO.

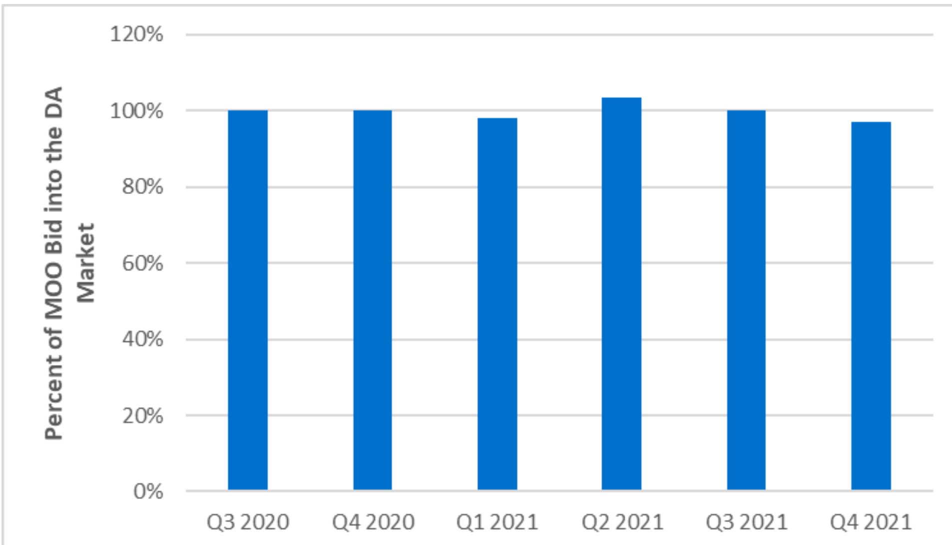
Figure 8-28: Percent of Must Offer Obligation bid into the Day-Ahead Market: *[REDACTED]*

[REDACTED]

[REDACTED]

Figure 8-29 shows the MOO compliance for *[REDACTED]*. *[REDACTED]* bid exactly 100% of their qualifying capacity into the DA market during three of the six evaluated quarters. They bid more than 100% in one of the three remaining months; Q2 2021 had the largest amount of capacity over the required amount bid into the market (103%). *[REDACTED]* bid 97% and 98% of their required capacity into the DA market during Q1 and Q4 2021, respectively; they were the only quarters in which *[REDACTED]* did not fulfill 100% of their bidding obligations.

Figure 8-29: Percent of Must Offer Obligation bid into the Day-Ahead Market: *[REDACTED]*



8.3 Minimum Dispatch Requirement

In 2019 the Commission established a new requirement for DRAM contracts beginning in 2021 to deliver 30 MWh per 1 MW of average Qualifying Capacity (QC).[62] This decision defines the "average QC" as the average of the three highest QC months, as per the month ahead Supply Plans, for each DRAM contract. In this section we assess the DRPs' compliance with this requirement in 2021.

Overall, the observations from the data suggest that the majority of DRPs and DRAM contracts fell short of fulfilling their minimum dispatch requirement in 2021. Compliance among DRPs varied from 14% to 175%. On an aggregate level, DRAM contracts cumulatively delivered about 70% of a 30 MWh per 1 MW of average QC obligation. The analysis is based on evaluating a total of 16 DRAM contracts, representing about 170 MWs of average QC.

8.3.1 Data Challenges

This assessment uses data from a variety of sources which were then needed to be mapped together such that the dataset allowed the Nexant Team to (1) identify which resource IDs

[62] D.19-12-040 Appendix C

belonged to which contracts and (2) what the monthly QC values were for each contract. The Team initially encountered significant challenges with mapping the necessary data pieces together as the source for each data point differed. After receiving higher quality mapping of resources to contracts for 2021, we were able to better assess how well the DRAM contracts met the new requirement. It should be noted that despite higher quality mapping, the Nexant Team was only able to evaluate contracts representing 170 MWs of average QC. Thus, it could be the case that not all contracts and/or resources were able to be fully included in the analysis to the extent the Team did not receive the complete mapping necessary. The mapping of resource IDs to contract IDs for prior years remained challenging, thus the Team was unable to calculate similar metrics for 2019-2020 for comparison purposes.

Specifically, CAISO settlement data was provided to the Nexant Team and was subset to only resources enrolled in DRAM and a select set of IOU-run DR programs. The data was cleaned and reformatted to fit the purposes of this analysis. Contracting data was required to compare contracted month-ahead qualifying capacity to CAISO-reported metered energy. Contracted months and month-ahead qualifying capacity were brought in from DRP-provided supply plans. To map resources to contracts, IOU-provided DRAM enrollment data was used. After addressing many discrepancies between the DRP supply plans' contract names, contracted months and the IOU-reported contract names and contracted months, the Nexant Team was able to compile a dataset for 2021 representing 16 DRAM contracts. It should be noted that not all resource IDs in the CAISO settlement data provided were mapped to a contract ID. It is the Team's assumption that those resources simply were not part of a DRAM contract during the months a mapping was not provided.

8.3.2 Methodology

There are two main inputs to measure performance to the requirement of 30 MWh per MW of average QC contracted: (1) energy delivery requirement for a unique DRAM contract and (2) actual energy delivery over a contract period from a unique DRAM contract.

The minimum energy delivery requirement adopted for the 2021 DRAM contract uses the average of the three highest monthly QC values for each DRAM contract. As such, the Nexant Team took an average of the three highest QC values for a unique DRAM contract ID over the contract term and this provided the average QC value in megawatts (MW). We multiplied this MW value by the 30 MWh/MW requirement to get the resulting total MWh a unique contract ID would be required to deliver over the DRAM commitment period. Below is a simple example of a DRAM contract with a monthly QC value each month of the year to illustrate this method.

Table 8-1: Example of Minimum Dispatch Requirement Calculation

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Monthly QC value (MW)	2.5	2.5	2.5	2.7	2.7	2.8	2.9	**3.1**	**3.1**	**3.1**	3.0	2.8

First, we take the highest three months of a QC value across the compliance period, in this case the calendar year. Then we average the top three QC values. This returns an average of 3.1

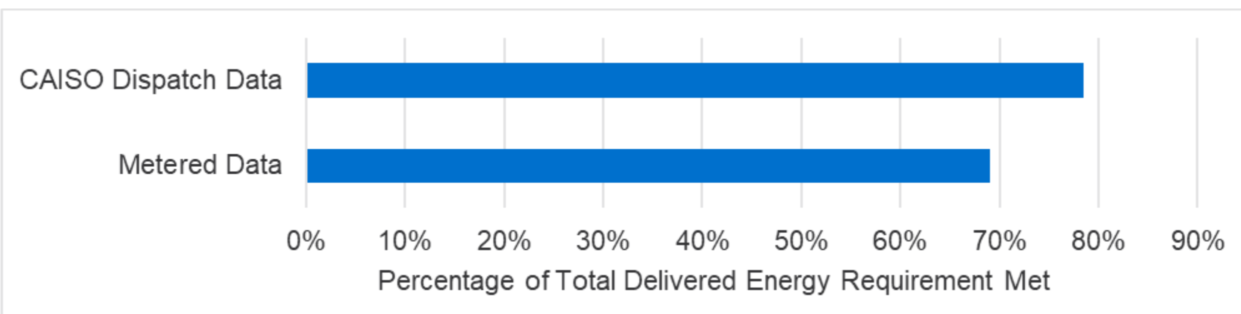
MW as the average QC value for this contract. Then we multiply that by 30 hours because the DRAM requirement is to deliver 30 MWhs per average 1 MW QC value. This means a contract with an average top-three monthly QC value of 3.1 MW will need to deliver at least 93 MWh of energy across the compliance period, in this case over the year, to meet the 2021 DRAM minimum dispatch requirement.

Actual energy delivery was a simple sum of energy delivery during Availability Assessment Hours (AAH) over a calendar year by unique contract ID for the months during which the contract was valid. The energy delivered was based on the metered data provided in the CAISO settlement dataset. The Team also looked at whether the DRPs would have met the requirement if their delivered energy matched their CAISO dispatch instruction as a “what-if” scenario, assuming 100% performance of each DRAM resource.

8.3.3 Aggregate-Level Analysis

Figure 8-30 summarizes all the cumulative DRAM contracts performance of delivered energy against a 30 MWh per average QC obligation. The results are then also presented by customer type – residential and non-residential – as shown in Table 8-2. These values are presented using the total metered MWhs across all DRAM contracts (Metered Data) and again using the expected energy (CAISO Dispatch) values from the CAISO settlement data. The Nexant Team opted to also evaluate the requirement using CAISO Dispatch data as a “what if” scenario. Specifically, to evaluate if the resources would have met the requirement assuming 100% performance.

Figure 8-30: Summary of Dispatch Compliance by Year – All DRPs – 2021



Cumulatively, the DRAM contracts delivered about 70% of a 30 MWh per average QC obligation. This is based on a total requirement of approximately 5,100 MWhs from the 16 DRAM contracts evaluated. When evaluated by contract, less than half of the DRAM contracts deliver enough energy to meet a 30 MWh per average QC compliance requirement. *[REDACTED].* Even if DRPs had performed at 100% (matching their CAISO dispatch values) still half of the contracts would have fallen short of meeting the contractual obligation; only three additional contracts would have met the delivery requirement.

Table 8-2: Summary of Contract Compliance – All DRPs – 2021

	Customer Type	Count of Contracts	Total Requirement (MWhs)	Contracts that Met Req.	MWhs of Contracts that Met Req.	% Of Contracts that Met Req.
Metered Data	Residential	[REDACTED]				
	Non-Residential	[REDACTED]				
	All	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	31%
CAISO Dispatch	Residential	[REDACTED]				
	Non-Residential	[REDACTED]				
	All	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	50%

Across all the contracts evaluated, there was a total requirement of 5,101 MWhs to be delivered during the Availability Assessment Hours (AAH) from resources within the 2021 DRAM contracts. The contracts that met the requirement represented approximately 23% of the 5,101 MWh total requirement; contracts representing 30% of the total requirement delivered 90% or more of the individual contractual requirement. Figure 8-31 shows, by contract, the amount of each contractual delivery requirement that was met (green bar) and what portion of the requirement was undelivered (orange bar) using the metered data. Figure 8-32 shows the same results but using the CAISO expected energy values as a measurement of delivered energy, which represents the “what if” scenario where each resource performed at 100% (i.e., metered data equals CAISO expected energy).

Figure 8-31: Delivered Energy Requirement Compliance by Contract – Metered Data – 2021

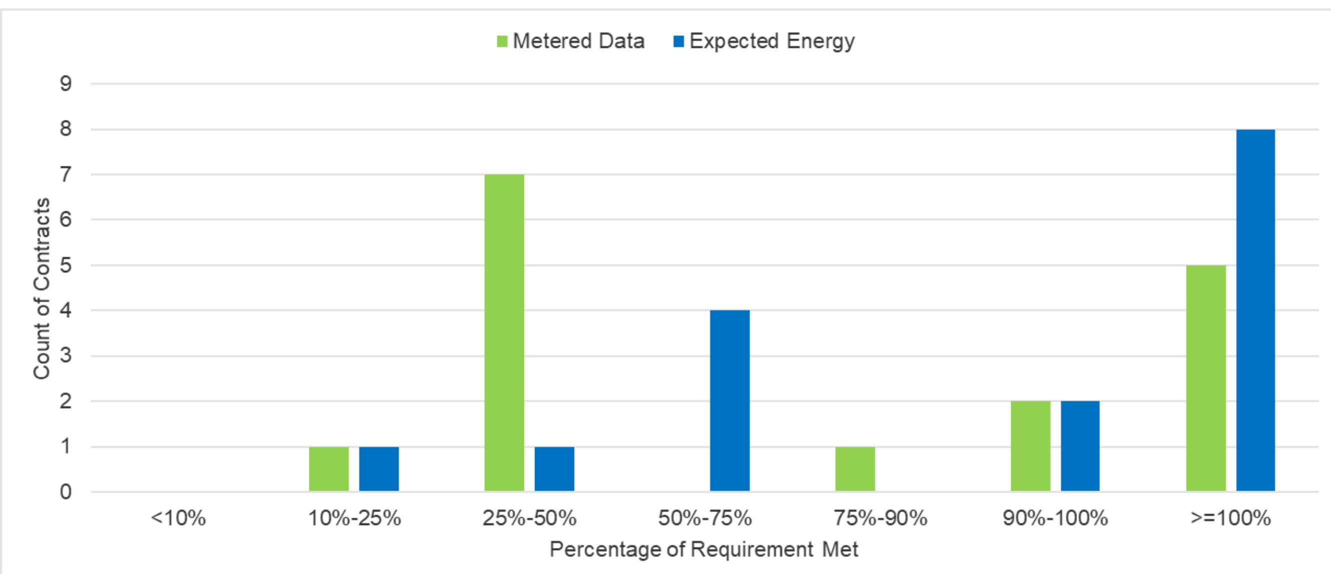
[REDACTED]

Figure 8-32: Delivered Energy Requirement Compliance by Contract – Expected Energy – 2021

[REDACTED]

Figure 8-33 groups each contract by the percentage of the requirement met, which is done using both the metered and expected energy values. Just under half of the contracts seem to be meeting at least 90% of the contractual requirement whereas the others are meeting anywhere between 13% and 42% of the requirement. There are some contracts that delivered above their minimum dispatch requirements.

Figure 8-33: Delivered Energy Compliance by Contract – Distribution of Performance – 2021



8.3.4 DRP-Level Analysis

Looking at the DRP-level data, we see that some contracts and DRPs have performed better than others. *[REDACTED].*

Table 8-3: Delivered Energy Requirement Compliance by DRP

DRP	Contract ID	Requirement	Percent of Requirement Met (Metered)	Percent of Requirement Met (Expected Energy)
[REDACTED]	*[REDACTED]*	*[REDACTED]*	*[REDACTED]*	*[REDACTED]*
[REDACTED]				
[REDACTED]				
[REDACTED]				
[REDACTED]				
[REDACTED]				
[REDACTED]				
[REDACTED]				
[REDACTED]				
[REDACTED]				
[REDACTED]				
[REDACTED]				
[REDACTED]				
[REDACTED]				
[REDACTED]				
[REDACTED]				

Overall, the analysis shows that less than 35% of the contracts met the 2021 minimum delivered energy requirement, with almost 50% of the contracts delivering at least 90% of the requirement. The contracts that fell significantly short of meeting the requirement were held by *[REDACTED]*.

8.4 Discussion

Criterion 5 seeks to evaluate if DRPs met their contractual obligations and were able to successfully provide their contracted capacity. This evaluation assessed three types of contract compliance: alignment between contracted capacity, supply plan capacity, and demonstrated capacity; compliance with the must-offer obligation (MOO); and compliance with the minimum energy requirement (effective for 2021 deliveries).

First, the contracted capacity, Supply Plan capacity, and demonstrated capacity were compared to determine whether DRPs were able to aggregate and deliver contracted capacity in a timely manner. DRPs' contract compliance was measured by assessing the ability of the DRPs to align Supply Plan and demonstrated capacity with contracted capacity. Table 8-4 presents a summary of contract compliance for 2018, 2019, 2020, and 2021. In 2018, DRPs[63] were mostly able to demonstrate capacity in close alignment (within about 97%) with the contracted capacity. Demonstrated capacity was mostly based on MOO during this pilot year. DRP compliance was slightly lower from 2019 to 2021, where demonstrated capacity alignment ranged from 79% in 2019 to 65% in 2021. Demonstrated capacity alignment varied considerably across DRPs.

Table 8-4: Summary of Contract Performance (2018-2021)

All DRPs (MW)	Delivery Year			
	2018	2019	2020	2021[64]
Contracted Capacity	1,089	2,147	1,366	1,821
Qualifying Capacity	1,079	1,905	1,233	1,440
Demonstrated Capacity	1,053	1,705	973	1,175
Demonstrated Capacity Alignment (%)	97%	79%	71%	65%

When looking at demonstrated capacity for the entire year, most of the invoiced capacity is based on DRPs' Must-Offer Obligation (MOO); which is to bid their capacity into the CAISO's market during the Availability Assessment Hours (AAH). In 2018, 2019, 2020, and 2021 the percentage of MOO-based DC invoices were 77%, 84%, 53%, and 44% respectively. The mix of demonstrated capacity types was not consistent across DRPs.

Table 8-5: Summary of Demonstrated Capacity Types (2018-2021)

All DRPs (%)	Delivery Year			
	2018	2019	2020	2021
MOO Based DC Invoices	77%	84%	53%	44%
Dispatch Based DC Invoices	18%	12%	32%	61%
Capacity Test Based DC Invoices	5%	14%	11%	1%

Next, MOO compliance was evaluated by comparing total DA market bids to each DRP's MOO for Q3 2020 through Q4 2021. DRPs collectively bid at least 100% in every quarter of the evaluation cycle and bid over 100% in every quarter but Q4 2020. When examining results for each individual DRP, MOO compliance varies. In Q3 the total MOO for all DRPs was 62 GWh;

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[63] *[REDACTED].*

[64] *[REDACTED].*

conversely, DRPs bid over 66 GWh of DR, into the DA market. At an aggregate level, DRPs were compliant with MOO requirements in all quarters of the evaluation period.

Table 8-6: Summary of Must-Offer Obligation Compliance (Q3 2020-Q4 2021)

All DRPs (%)	Delivery Quarter					
	Q3 2020	Q4 2020	Q1 2021	Q2 2021	Q3 2021	Q4 2021
DA Bid Quantity (MWh)	66,020	45,548	29,053	40,269	49,346	33,647
Must Offer Obligation Energy (MWh)	61,548	45,332	28,467	39,534	46,454	31,866
MOO Compliance (%)	107%	100%	102%	100%	106%	102%

Finally, this Criterion assessed how well the DRAM contracts met a new minimum dispatch requirement set for DRAM contracts beginning in 2021.[65]

- Overall, this analysis regarding the new energy delivery requirement for 2021 shows that less than 35% of the contracts, representing 23% of the energy delivery requirement, were in compliance with the new requirement.
- Most contracts that were not in compliance with the new requirement were held by *[REDACTED]*, with the remaining contracts all meeting, or nearly meeting (at least 90%), the requirement.
- Performance did not have a significant impact on DRPs not meeting the energy delivery requirement. Even if all the resources performed 100% (i.e., metered data equal to CAISO Dispatch) only two additional contracts would have been in compliance.

[65] D.19-12-040 established the new minimum dispatch requirement for DRAM resources starting in 2021.

9 Criterion 6: Were Resources Reliable When Dispatched?

Criterion 6 assesses the reliability of the DRAM resources in reducing load when called upon by the CAISO market. This evaluation assesses DRP's market performance by evaluating the DRP's total real-time (RT) market awards relative to their total delivered energy.

The 2019 Energy Division DRAM Evaluation assessed each resource's market performance, comparing its delivered energy amount to both the day-ahead (DA) and real-time (RT) awarded energy. This ratio provided an indication of the effectiveness of a resource in reducing the CAISO load when the CAISO market called upon it to do so, as indicated by receiving a CAISO DA and/or RT energy schedule. The Energy Division's Final Report found that there was mixed performance across demand response resources; some resources performed very well while others did not perform to their schedules.

The CAISO dispatches resources using three separate but sequential schedules in its energy market; a DA schedule, a fifteen-minute schedule, and then ultimately a 5-minute or "real-time" schedule. Each subsequent market run essentially provides an updated schedule for the resource as it nears real-time. It is this final 5-minute RT award that the CAISO requires all resources to meet. Therefore, this evaluation focuses on how well DRAM resources delivered energy compared to their 5-minute RT awards (also referred to as dispatch).

The CAISO DA market is a financial market, and while some resource types receive physically binding commitment and dispatch instructions, most are re-optimized in the RT based on RT bids and market conditions. Thus, in this evaluation we did not compare delivered energy to DA schedules.

In this evaluation we also assessed the accuracy of demonstrated capacity invoices, which are indicative of DRAM performance and are the basis of DRP's capacity payments. As such, it is important to assess the degree to which Scheduling Coordinator (SC)/DRP-reported delivered energy is accurate. For this evaluation, the Nexant Team estimated the delivered energy using the same baseline methods used by DRPs. These estimates were then compared to the SC-reported delivered energy, DRP-reported delivered energy and the CAISO RTM awards.

Initially, the scope of the evaluation also included an assessment of how reliable demand response resources were in being able to provide awarded ancillary services. *[REDACTED].*[66] Thus, the evaluation report does not include an assessment of DRAM resources providing ancillary services.

[66] *[REDACTED].*

9.1 Methodology

9.1.1 Performance Calculation based on CAISO Settlement Data

This subsection describes the approach used by Nexant Team to assess overall performance using CAISO award and settlement data from January 2018 to December 2021. As noted above, because the CAISO's 5-minute RT is the final schedule provided to a resource, this aspect of the evaluation focuses on comparing the resource metered data as provided by the CAISO settlement data to the 5-minute RT schedule (also referred to as award or dispatch) rather than any prior one. The metered data within the CAISO settlement data is reported to the CAISO by the scheduling coordinators of the resources.

The main performance evaluation was conducted by comparing DRAM resources delivered energy to CAISO RT award (or dispatch) across two methodologies: time-based over a 5-minute period and event-based period over a variable period of time depending on the length of the event.

- Time-Based; performance is calculated using 5-minute granular data. This uses the raw metered data and divides it by the CAISO 5-minute RT dispatch in that interval.
- Event-Based; performance is calculated on an event basis. This uses the summation of the raw metered data of all 5-minute intervals within the event horizon and divides it by the summation of the CAISO 5-minute RT dispatch of each interval within the event horizon.

The time-based methodology assesses performance accuracy using the individual 5-minute performance value, i.e., how well did the DRAM resource provide energy compared to the 5-minute award. The event-based methodology assesses performance over an entire event, i.e., how well did the DRAM resource provide energy over the entire period of need.

For the time-based assessment we capped the performance within each 5-minute interval at 100%. This was done because while in each interval a DRAM resource may reduce load more than the CAISO award, from a reliability perspective, that does not necessarily benefit reliability in another 5-minute interval. In other words, the assessment does not allow over performance in one interval to off-set under performance in another.

Over the event-based assessment periods, the evaluation focuses on the distribution of performance by year and DRP. This was done to assess if there is (1) consistent performance throughout all the events and (2) if performance tends to be concentrated around a certain level. The metered data value used for each interval within the horizon is capped at the CAISO 5-minute dispatch value prior to taking the summation across the event horizon such that over-performance in one interval does not mask under-performance in another interval within the same event.

9.1.2 Nexant-Calculated vs DRP/SC-Reported Delivered Energy Comparison

This subsection describes the approach used by the Nexant Team to independently estimate delivered energy for DRAM dispatches in the RTM. These values were then compared to the ones reported by DRPs and their SCs which are used for IOU and CAISO settlements and payments. The Nexant Team and the DRPs used the same CAISO-approved PDR performance evaluation methodology to calculate delivered energy. Due to constraints in time and resources, this comparison analysis was limited to Q3 and Q4 2020.

The first step for this comparison was to determine which hours to include in the analysis. The key source of event data was DRP-provided quarterly reports that included hourly information for each DRAM resource ID for each hour in the AAH window. Events were defined to be hours in which the DRP reported a market dispatch with an expected energy delivery over zero MWh. The quarterly reports also included DRP-reported baseline energy, baseline adjustment factors, metered energy, and delivered energy. Nexant cross-checked the DRP-reported event hours with CAISO data to ensure that both sources recorded an event.

Next, the Team determined which customers were dispatched for each event. DRP-provided enrollment data was utilized to map customers to their respective resource IDs. Each DRP provided enrollment data including resource ID, a customer identifier and enrollment start and end dates. In short, DRP enrollment data was used to discern which customers were present for each reported event. Finally, each customer in the DRP enrollment data was mapped to their unique IOU account using unique utility customer identifiers. Customer characteristics data provided by the IOUs was used to determine account activation and deactivation dates as well as the account type (residential or non-residential). This data was also used to map customers to IOU-provided advanced metering infrastructure (AMI) data.

From these five data sources, an analysis dataset was developed to include necessary components for the baseline analysis. This dataset included: all events and their reported metrics according to the DRP's quarterly reports, all customers enrolled in each dispatched resource during each event, the enrolled customers smart meter usage on event and potential baseline days. To reduce bias, the Nexant Team evaluated event hours for which 95% or more customers enrolled in the resource had available data, and only events that were reported with complete data from the DRP's quarterly reports.

DRPs estimate and report delivered energy and other energy metrics for DRAM events using one of several CAISO-approved baseline methodologies. Baseline methodologies allow DRPs to estimate customer baseline loads and demand response energy measurements using customer meter data from similar non-event days as a counterfactual for the event.[67] DRPs used one of three methods which the Team recreated in this analysis: Day Matching 10-in-10, Day Matching 5-in-10, and Combined. In their quarterly reports, the DRPs indicated which baseline methodology they used to calculate delivered energy for each event, which the Nexant Team then replicated to compare the results.

[67] CAISO (2020). Tariff 8741*: Performance Evaluation Methods for PDRs and RDRRs*. Section 4.13.4.

Equation 9-1: Day Matching 10-in-10 Adjustment Calculation

$$Pre - Event\ Adjustment = \frac{\left(\frac{Usage_{H1} + Usage_{H2} + Usage_{H3}}{3}\right)_{Event}}{\left(\frac{Usage_{H1} + Usage_{H2} + Usage_{H3}}{3}\right)_{Baseline}}$$

Table 9-1 illustrates the adjustment window used in the Day Matching 10-in-10 baseline calculation method.

Table 9-1: Day Matching 10-in-10 Adjustment Window

	Adjust-ment Hour 1	Adjust-ment Hour 2	Adjust-ment Hour 3	Gap	Gap	Event Start	Event Hour	Event End
Hour-ending	12	13	14	15	16	17	18	19

The minimum adjustment factor is 80% and the maximum is 120%. For example, if the calculated adjustment is greater than 120% it is replaced with 120%. Equation 9-2 shows that the unadjusted baseline use for each event hour is multiplied by the adjustment factor to calculate the adjusted baseline energy value.

Equation 9-2: Adjusted Baseline Calculation

$$Adjusted\ Baseline\ MWh = Unadjusted\ Baseline\ MWh * Adjustment\ Value$$

The metered energy use, the aggregate energy use of customers within the resource ID on the event day, is subtracted from the estimated adjusted baseline energy use for each event hour to determine the Nexant-calculated delivered energy. Equation 9-3 illustrates the final calculation, yielding the Nexant-calculated delivered energy (MWh) for a given event hour.

Equation 9-3: Delivered Energy Calculation

$$\begin{aligned} &Nexant\ Calculated\ Delivered\ Energy\ MWh \\ &\qquad = Adjusted\ Baseline\ MWh - Metered\ Energy\ MWh \end{aligned}$$

The Day Matching 5-in-10 baseline method is only applicable to residential DRAM customers. For resources evaluated by the DRP using the 5-in-10 method, the Team first selected forty-five (45) days prior to the event as potential base days. As with the 10-in-10 method, holidays, other event days, weekends, and outages were removed from the set of potential baseline days. The remaining ten days immediately prior to the event are then sorted by total load during the hours in which the resource was dispatched on the event day. The five days with the highest event hour load, within the remaining 10 days, are selected as baseline days. If five baseline days were not available, a minimum of four was used. Then, the unadjusted baseline value was calculated by averaging the aggregate hourly usage of all customers within the resource for the remaining baseline days. The Team then calculated an adjustment factor which represents the percent difference in load between event and base day for fifth through third hours proceeding the event start, and the third and fourth hours following the event. Table 9-2 illustrates the adjustment window utilized by the Day Matching 5-in-10 baseline calculation method.

Table 9-2: Day Matching 5-in-10 Adjustment Window

	Adjust-ment Hour 1	Adjust-ment Hour 2	Gap	Gap	Event Start	Event Hour	Event End	Gap	Gap	Adjust-ment Hour 3	Adjust-ment Hour 4
Hour-ending	12	13	14	15	16	17	18	19	20	21	22

Usage for these four hours is averaged for both the event and baseline days, then the average pre- and post-event usage for event day is divided by the average pre- and post-event usage on the average baseline day. The adjustment value is then capped at 140% with a minimum of 71%. For example, if the adjustment is greater than 140% it is replaced by 140%. Then, unadjusted baseline use for each event hour is multiplied by the adjustment value to calculate the adjusted baseline energy value. The metered energy use, the aggregate energy use of customers within the resource ID on the event day, is subtracted from the estimated adjusted baseline energy use for each event hour to determine the Nexant-calculated delivered energy.

Finally, the Day Matching Combined method for baseline analysis is applicable to both residential and non-residential DRAM resources. Residential customers and non-residential customers total load is segmented out and analyzed separately. Within a resource for a given event, residential customer load is evaluated using the Day Matching 5-in-10 method as described above, and non-residential customers' totalized load is evaluated using the Day Matching 10-in-10 method. Once metered and adjusted baseline energy values are calculated using the respective methods, they are combined to reflect the entire resource's metered and adjusted baseline load for the event hours. Then aggregate metered energy is subtracted from the aggregate adjusted baseline energy to calculate the delivered energy for each event hour.

For the comparison exercise the Nexant Team compared the four metrics below for July 1 through December 31, 2020:

- CAISO-reported dispatched energy (Source: CAISO Settlement Data)
- SC-reported delivered energy (Source: CAISO Settlement Data)
- DRP-reported delivered energy (Source: DRAM Quarterly Reports)
- Nexant-calculated delivered energy (Source: calculated from customer meter data)

All values were aggregated to monthly MWh by DRP by summing across the available events. DRP-reported and Nexant-calculated delivered energy estimates were allowed to be negative if estimated baseline energy was lower than metered energy.

9.2 Performance of DRAM Resources – Time Based

9.2.1 Performance by Year

This section evaluates DRAM resource performance by year under difference scenarios. CAISO settlement data is the main data source for this analysis. The analysis in this section caps performance in each interval such that over performance in one interval does not mask under performance in another. Capping performance at 100% provides a better measure of how well DRAM resources are meeting their schedule. The CAISO 5-minute real-time (RT) dispatch (or award) is not a minimum dispatch, but a target that resources are expected to reach. Thus, capping the performance at 100% (which is the most the CAISO is asking for) shows how well DRPs are meeting the RT dispatch on average.

The average performance by year is shown in Table 9-3, followed by a breakdown by DRP in Table 9-4. In each table, the total CAISO dispatched MWhs are provided to give additional context. For example, a DRP's performance that only represents a small portion of the overall DRAM dispatched MWhs should be weighed less than a DRP's performance with a significant amount of dispatched MWhs when evaluating the DRAM program as a whole.

As shown in the data below, the performance does increase year over year, but there remain some DRPs with more room for improvement. Additionally, the lower performing DRPs tend to represent a significant portion of the overall dispatched MWhs.

Table 9-3: Average Performance by Year

Year	Average Performance	Total CAISO Dispatch (MWhs)
2018	51%	834
2019	71%	3,553
2020	84%	4,314
2021	84%	5,911

Table 9-4: Average Performance by Year, by DRP

DRP	2018		2019		2020		2021	
	Avg. Performance	CAISO Dispatch (MWhs)	Avg. Performance	CAISO Dispatch (MWhs)	Avg. Performance	CAISO Dispatch (MWhs)	Avg. Performance	CAISO Dispatch (MWhs)
[REDACTED]	*[REDACTED]*		*[REDACTED]*		*[REDACTED]*		*[REDACTED]*	
[REDACTED]								
[REDACTED]								
[REDACTED]								
[REDACTED]								
[REDACTED]								
[REDACTED][68]								
[REDACTED]								

9.2.2 Performance by Dispatch Category

This section evaluates performance by size of dispatch. This evaluates whether the size of the RT award (i.e., the dispatch level) impacts performance.[69] Table 9-5 shows how well the DRPs in aggregate performed in meeting their CAISO RT dispatch in each delivery year, by dispatch level. Each 5-minute interval dispatch was first categorized by dispatch level. The Nexant Team then took the average performance of all 5-minute intervals within that dispatch category.

Table 9-5: Average Performance by Year, by Dispatch Level

Dispatch Level	2018	2019	2020	2021
<=0.01 MW	75%	83%	96%	96%
0.01 MW - 1 MW	46%	66%	52%	82%
1 MW - 3 MW	62%	32%	70%	93%
>3 MW	88%	38%	86%	93%

Overall, there does not appear to be a strong correlation between the size of dispatch level and performance. Table 9-6 and Table 9-7 breaks up the above data by DRP. This shows the significant variability of performance across DRPs.

68 *[REDACTED].*

69 The dispatch level is the operating point the CAISO market dispatched the resource to in a given 5-minute interval, not the delivered energy in that 5-minute interval. For example, a dispatch level of 1MW means the resource was expected to generate at the 1MW set point. If the resource was dispatched at 1MW for one 5-minute interval it would have been expected to deliver 1/12MWh of energy.

Table 9-6: Average Performance by Year, by Dispatch Level, by DRP (1 of 2)

Year	Dispatch Category	*[REDACTED]*		*[REDACTED]*		*[REDACTED]*		*[REDACTED]*	
		Avg. Performance	CAISO Dispatch (MWhs)	Avg. Performance	CAISO Dispatch (MWhs)	Avg. Performance	CAISO Dispatch (MWhs)	Avg. Performance	CAISO Dispatch (MWhs)
2018	<=0.01 MW	*[REDACTED]*		*[REDACTED]*		*[REDACTED]*		*[REDACTED]*	
	0.01 MW - 1 MW								
	1 MW - 3 MW								
	>3 MW								
2019	<=0.01 MW	*[REDACTED]*		*[REDACTED]*		*[REDACTED]*		*[REDACTED]*	
	0.01 MW - 1 MW								
	1 MW - 3 MW								
	>3 MW								
2020	<=0.01 MW	*[REDACTED]*		*[REDACTED]*		*[REDACTED]*		*[REDACTED]*	
	0.01 MW - 1 MW								
	1 MW - 3 MW								
	>3 MW								
2021	<=0.01 MW	*[REDACTED*		*[REDACTED*		*[REDACTED]*		*[REDACTED*	
	0.01 MW - 1 MW								
	1 MW - 3 MW								
	>3 MW								

Table 9-7: Average Performance by Year, by Dispatch Level, by DRP (2 of 2)

Year	Dispatch Category	[REDACTED]		[REDACTED]		[REDACTED]		[REDACTED]	
		Avg. Performance	CAISO Dispatch (MWhs)	Avg. Performance	CAISO Dispatch (MWhs)	Avg. Performance	CAISO Dispatch (MWhs)	Avg. Performance	CAISO Dispatch (MWhs)
2018	<=0.01 MW	*[REDACTED]*		*[REDACTED]*		*[REDACTED]*		*[REDACTED]*	
	0.01 MW - 1 MW								
	1 MW - 3 MW								
	>3 MW								
2019	<=0.01 MW	*[REDACTED]*		*[REDACTED]*		*[REDACTED]*		*[REDACTED]*	
	0.01 MW - 1 MW								
	1 MW - 3 MW								
	>3 MW								
2020	<=0.01 MW	*[REDACTED]*		*[REDACTED]*		*[REDACTED]*		*[REDACTED]*	
	0.01 MW - 1 MW								
	1 MW - 3 MW								
	>3 MW								
2021	<=0.01 MW	*[REDACTED]*		*[REDACTED]*		*[REDACTED]*		*[REDACTED]*	
	0.01 MW - 1 MW								
	1 MW - 3 MW								
	>3 MW								

Individual DRP performance also does not appear significantly impacted by the size of dispatch. *[REDACTED].*

9.3 Performance of DRAM Resources – Event Based

While the CAISO expects resources to meet their RT dispatch, another way to assess DRAM performance is by examining their ability to provide expected energy across an entire event. This measures how well the PDR resource provided energy over the entire period of need, even if performance was high or low in any individual 5-minute period. Given the uncertainty inherent in demand response resources, the event-based metric shows the contribution of DRAM resources to reliability overall.

An event is defined as the period when the DRAM resource begins being dispatched by the CAISO until its award goes to zero MWh. One way to evaluate event-based performance is to sum the metered energy of that resource for all 5-minute intervals within the event horizon and then divide that by the summation of the total expected energy within the same horizon. This provides a performance metric for that resource event. However, this then allows over-performance in one 5-minute interval to off-set under-performance in another. Using this methodology may mask potential reliability concerns. Thus, the Nexant Team opted to take an alternative approach.

For the event-based assessment, the Nexant Team first capped the metered data for each 5-minute interval at the CAISO 5-minute dispatch level such that over performance in one interval cannot off-set under-performance in another interval within the same event horizon. Then the Team summed the capped metered data and divided it by the summation of the CAISO 5-minute dispatch level within the event horizon. This ratio created an event performance metric indicating how well the resource performed to the CAISO's expectation for each interval within the event horizon. The performance of each event is then evaluated in terms of distribution by year and DRP.

Figure 9-1 and Table 9-8 show the distribution of the event-based performances by year. In each of the first two years (2018 and 2019) only 30% of the events have relatively high performance (i.e., at least 90%). Starting in year 2020, performance does seem to increase with 2021 having nearly half of the events with performance greater than 90%. *[REDACTED].* However, the performance for the other events, in all years, seems to have a steep drop rather than a more gradual drop in performance. This seems to indicate that there is a small concentration of events with high performance after which the performance drastically degrades, with several dropping well below 50% performance. As highlighted during the August 2020 black outs, during the highest system need periods, even a slight difference between expected delivery and actual can cause reliability concerns.

Figure 9-1: Event Based Performance Distribution by Year

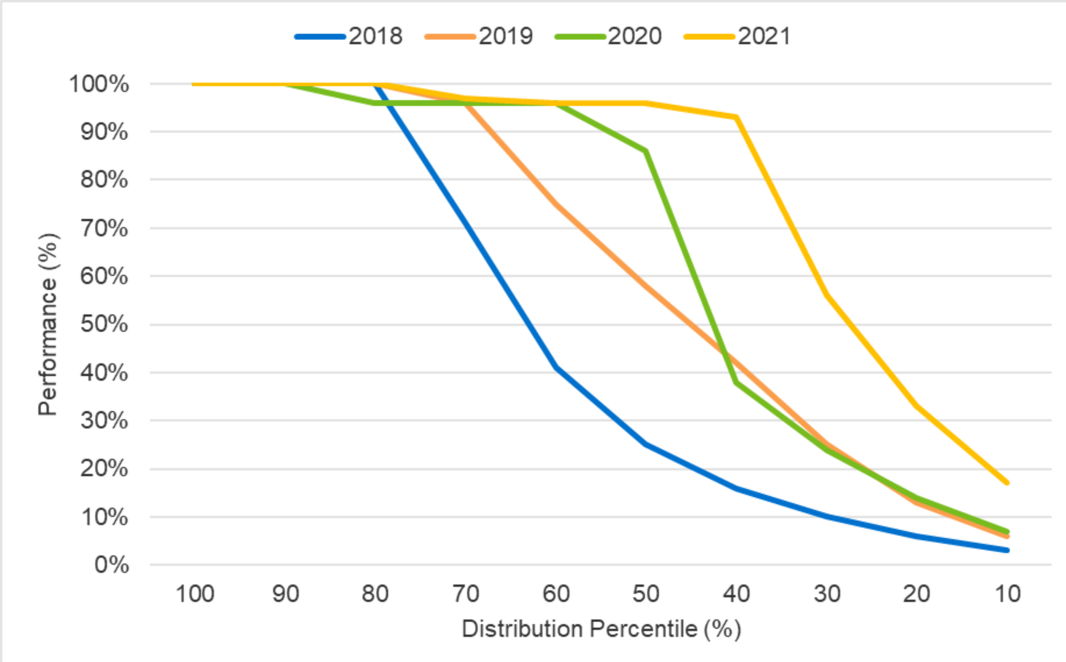
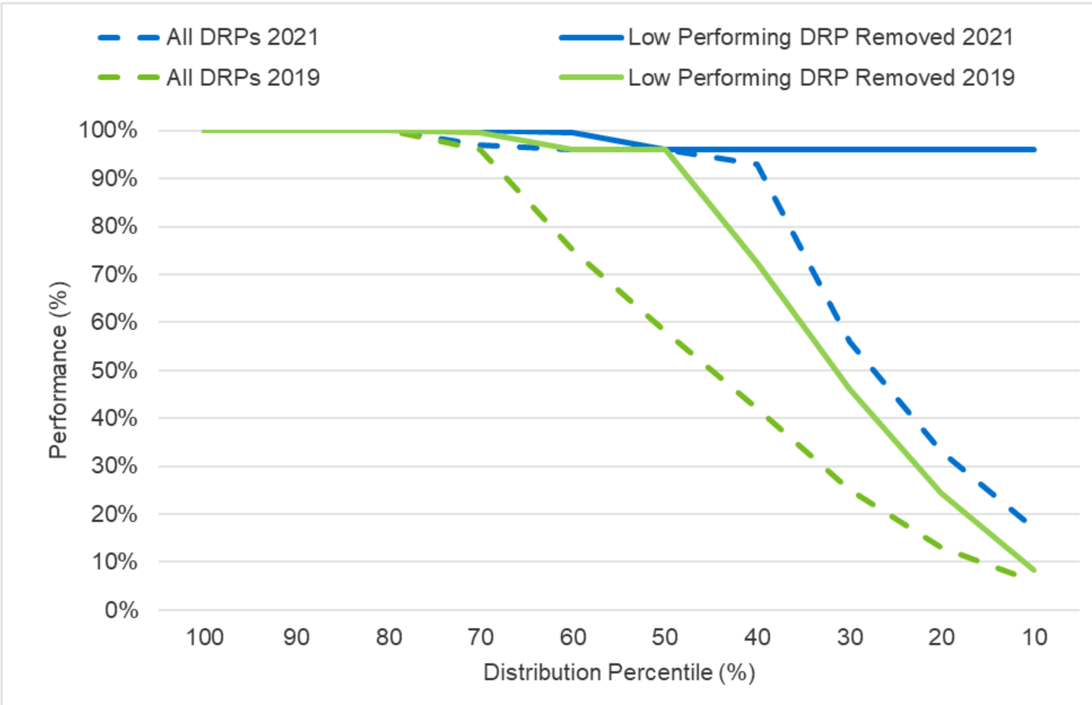


Table 9-8: Event Based Performance Percentiles by Year

Year	Min	25th Percentile	Median	75th Percentile	Max
2018	0%	8%	25%	93%	100%
2019	0%	19%	58%	100%	100%
2020	0%	19%	86%	96%	100%
2021	0%	43%	96%	100%	100%

The pattern of performance dropping off starting around the 60th percentile may be driven primarily from one low performing DRP. Figure 9-2 shows a comparison of the distribution of the event-based performances with and without the lowest performing DRP(s) *[REDACTED]*. For purposes of this evaluation, the Team has defined low performance as a DRP with consistent underperformance. *[REDACTED].*

Figure 9-2: Impact of Lowest Performing DRP on Event Based Performance Distribution



The following four tables show the event-based performance percentiles by DRP and year. Clearly there are some DRPs that, based on the data, seem to perform well throughout all their events. However, it should be noted that the DRPs with high performance throughout all their events are also the DRPs with the least number of events. This may skew their percentiles upward if, for example, 10 out of 12 events were at 90% performance versus another DRP that may have 600 out of 1,000 events at 90% performance. The latter would be considered to have a lower performance based on the percentiles.

Table 9-9: 2018 Event Based Performance Percentiles by DRP

DRP	Min	25th Percentile	Median	75th Percentile	Max
[REDACTED]	*[REDACTED]*	*[REDCATED]*	*[REDCATED]*	*[REDCATED]*	*[REDCATED]*
[REDACTED]					
[REDACTED]					
[REDACTED]					
[REDACTED][68]					

Table 9-10: 2019 Event Based Performance Percentiles by DRP

<table>
<tr><th>DRP</th><th>Min</th><th>25th Percentile</th><th>Median</th><th>75th Percentile</th><th>Max</th></tr>
<tr><td>[REDACTED]</td><td rowspan="7">[REDACTED]</td><td rowspan="7">[REDACTED]</td><td rowspan="7">[REDACTED]</td><td rowspan="7">[REDACTED]</td><td rowspan="7">[REDACTED]</td></tr>
<tr><td>[REDACTED]</td></tr>
<tr><td>[REDACTED]</td></tr>
<tr><td>[REDACTED]</td></tr>
<tr><td>[REDACTED]</td></tr>
<tr><td>[REDACTED]</td></tr>
<tr><td>[REDACTED][68]</td></tr>
</table>

Table 9-11: 2020 Event Based Performance Percentiles by DRP

<table>
<tr><th>DRP</th><th>Min</th><th>25th Percentile</th><th>Median</th><th>75th Percentile</th><th>Max</th></tr>
<tr><td>[REDACTED]</td><td rowspan="6">[REDACTED]</td><td rowspan="6">[REDACTED]</td><td rowspan="6">[REDACTED]</td><td rowspan="6">[REDACTED]</td><td rowspan="6">[REDACTED]</td></tr>
<tr><td>[REDACTED]</td></tr>
<tr><td>[REDACTED][68]</td></tr>
<tr><td>[REDACTED]</td></tr>
<tr><td>[REDACTED]</td></tr>
<tr><td>[REDACTED]</td></tr>
</table>

Table 9-12: 2021 Event Based Performance Percentiles by DRP

<table>
<tr><th>DRP</th><th>Min</th><th>25th Percentile</th><th>Median</th><th>75th Percentile</th><th>Max</th></tr>
<tr><td>[REDACTED]</td><td rowspan="6">[REDACTED]</td><td rowspan="6">[REDACTED]</td><td rowspan="6">[REDACTED]</td><td rowspan="6">[REDACTED]</td><td rowspan="6">[REDACTED]</td></tr>
<tr><td>[REDACTED]</td></tr>
<tr><td>[REDACTED]</td></tr>
<tr><td>[REDACTED]</td></tr>
<tr><td>[REDACTED]</td></tr>
<tr><td>[REDACTED]</td></tr>
</table>

Overall, the event-based performance shows that while each DRP is capable of performing to CAISO's expectation based on the RT dispatch instructions, the variation of performance is rather significant. Furthermore, the variation seems to exist between DRPs, meaning that some

DRPs tend to perform relatively well in a consistent manner based on both the time-based and event-based metrics but those also tend to be the DRPs with fewer dispatches.

9.4 Nexant-Calculated Delivered Energy Comparison Findings

For this analysis the Nexant Team compared the below four metrics against each other:

- CAISO-reported dispatched energy (Source: CAISO Settlement Data)
- SC-reported delivered energy (Source: CAISO Settlement Data)
- DRP-reported delivered energy (Source: DRAM Quarterly Reports)
- Nexant-calculated delivered energy (Source: calculated from IOU AMI data)

Due to constraints in time and resources, this comparison analysis was limited to Q3 and Q4 2020. First, the Team evaluated the DRPs' accuracy in calculating their baseline, metered, and delivered energies by comparing Nexant-calculated delivered energy to the DRP-reported delivered energy. The Team also evaluated the accuracy of the DRPs' reporting by comparing both Nexant and DRP-reported delivered energy to SC-reported delivered energy. It's reasonable to expect that DRP-reported delivered energy and SC-reported delivered energy should be identical, however it is often not. Next, the Team evaluated the performance of the DRPs by comparing Nexant-calculated delivered energy to CAISO-reported dispatched energy or expected energy for each month. This shows how close DRPs were to achieving their expected energy at an aggregate monthly level. The following figures show how the DRPs performed in each metric, by month. Note that DRPs who were not contracted for every month between July and December 2020 are missing the months where they had no event dispatches.

9.4.1 Aggregate-Level Analysis

Figure 9-3 compares aggregate CAISO-reported dispatched MWh for all contracted DRPs and all event hours that met Nexant's data requirements to SC-reported delivered MWh, DRP-reported delivered MWh and Nexant-calculated delivered MWh for the same resources and hours, by month. In July, August, September, and October, dispatched energy is larger than all three delivered energy values, showing that DRAM underperformed as a whole in these months. Dispatched energy is greater than SC-reported and Nexant-calculated delivered energy, but not DRP-reported energy in all months from July 2020 through December 2020. DRP-reported delivered energy is larger than Nexant-calculated delivered energy in all months, but most notably in July, November, and December. In November and December, DRP-reported delivered energy is larger than CAISO-reported dispatched, SC-reported delivered energy, and Nexant-calculated delivered energy. In short, there is considerable variability in the accuracy, performance, and magnitude of delivered energy by month.

Figure 9-3: Dispatched and Delivered MWh: All DRPs

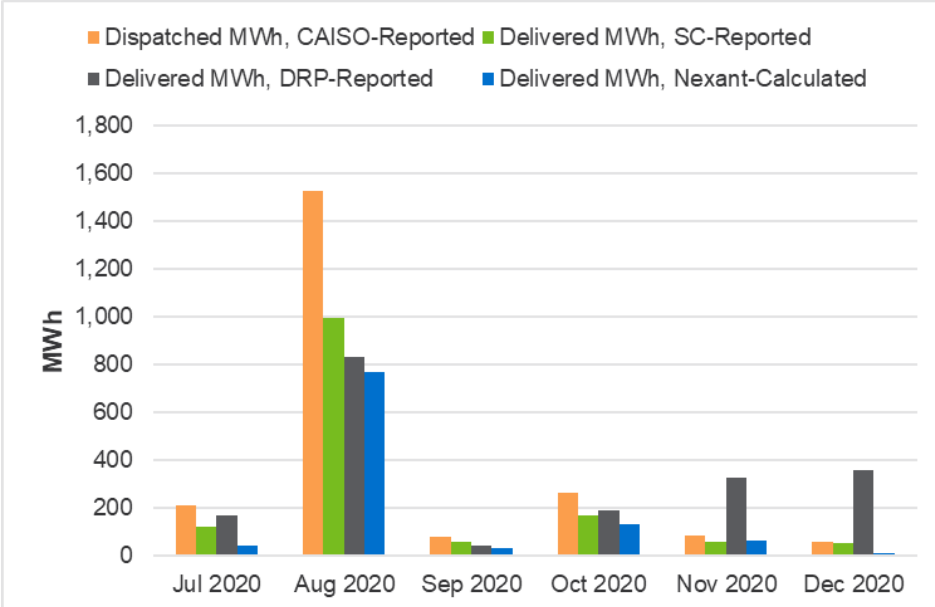
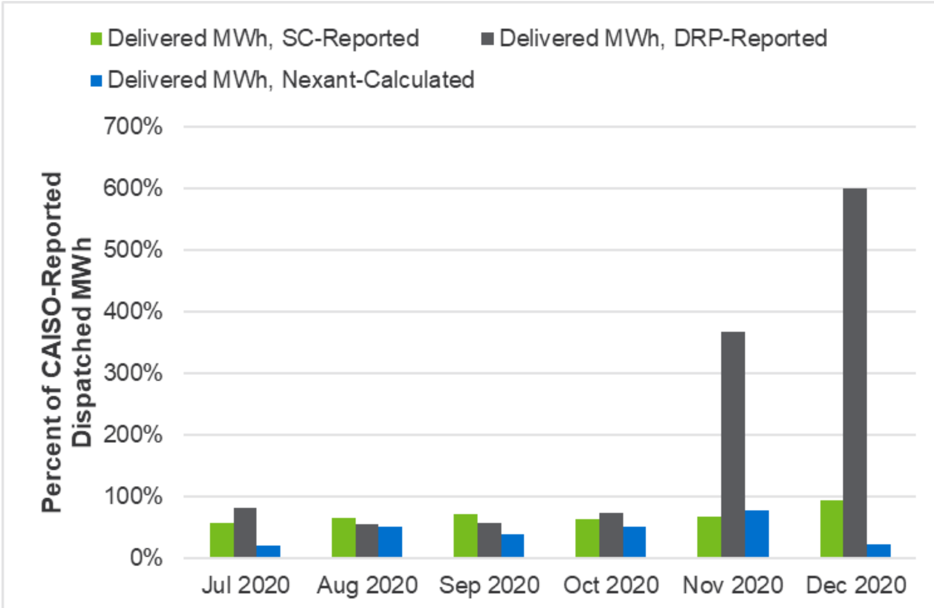


Figure 9-4 presents SC-reported, DRP-reported, and Nexant-calculated delivered energy as a percentage of CAISO-reported dispatched energy for all DRPs and eligible events by month. For example, if CAISO-reported dispatched energy was 1 MWh and DRP-reported delivered was 0.6 MWh, then it is shown as 60% on the figure below. In other words, this figure presents DRP performance using the three calculations described previously. For DRAM as a whole, SC-reported delivered energy as a percent of CAISO dispatched energy ranges from 57% in July to 93% in December. Conversely, DRP-reported performance ranged widely. DRP-reported performance is relatively stable around 75% in the months of July-October 2020, but spikes to 367% in November and 600% in December. Nexant-calculated delivered energy ranged from 20% in July to 76% in November. Note that *[REDACTED]*, and *[REDACTED]* greatly over-reported their delivered energy in both months compared to SC-reported and Nexant-calculated delivered energy.

Figure 9-4: Delivered Energy as a Percentage of Dispatched Energy: All DRPs



9.4.2 DRP-Level Analysis

[REDACTED]

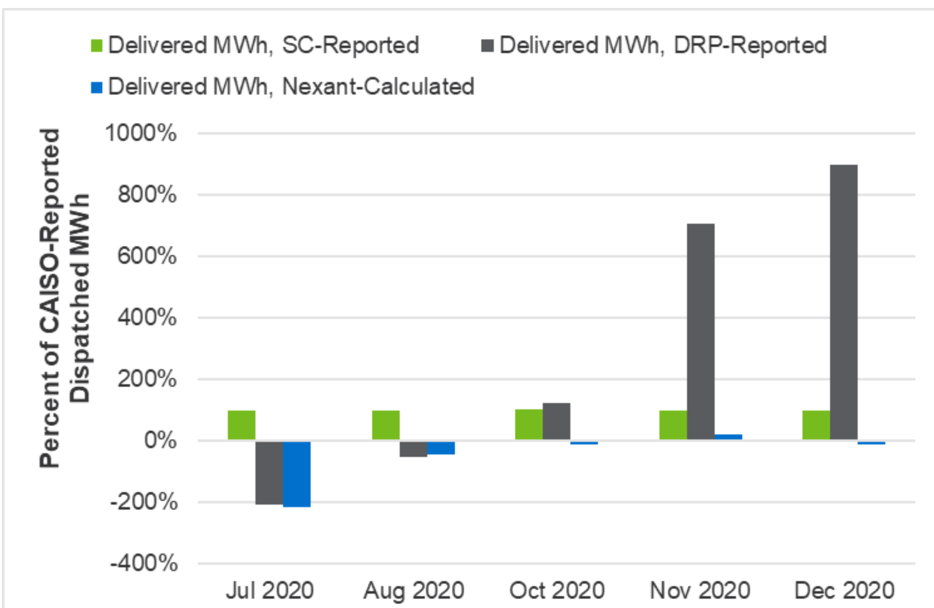
Figure 9-5 compares CAISO-reported dispatched MWh to SC-reported delivered MWh, DRP-reported delivered MWh, and Nexant-calculated delivered by month, for all *[REDACTED]* events that met Nexant's data requirements. Nexant-calculated delivered energy is negative in every month apart from November. There is evidence that *[REDACTED]*. Notice the CAISO-reported dispatched values are nearly identical to the SC-reported delivered energy in each month, while DRP-reported delivered energy varies between much lower and much larger than SC-reported delivered MWh. In July and August, *[REDACTED]* calculated negative delivered energy but reported positive delivered energy through the SC. In November and December, DRP-reported delivered energy is 45 and 87 times larger than Nexant-calculated delivered energy, respectively. It appears that the DRP may have made a multiplier error in these months, as the DRP-reported delivered energy is about 10 times larger than their SC-reported delivered energy and invoiced quantities. Additionally, in October, November and December, there were some events *[REDACTED]* reported 0 MWh for metered and baseline energy leading to DRP-reported delivered energy values of 0 during hours where Nexant-calculated delivered energy was negative, which also may have been in error.

Figure 9-5: Dispatched and Delivered MWh: *[REDACTED]*

[REDACTED]

Figure 9-6 displays *[REDACTED]*'s SC-reported, DRP-reported, and Nexant-calculated delivered energy as a percentage of CAISO-reported dispatched energy for all available events by month. *[REDACTED]*'s performance ranged between -218% and 18%. The DRP-reported performance ranges from -211% to 895%. Meanwhile, the SC-reported delivered energy consistently falls between 96% and 100% during these same months.

Figure 9-6: Delivered Energy as a Percentage of Dispatched Energy: *[REDACTED]*



[REDACTED]

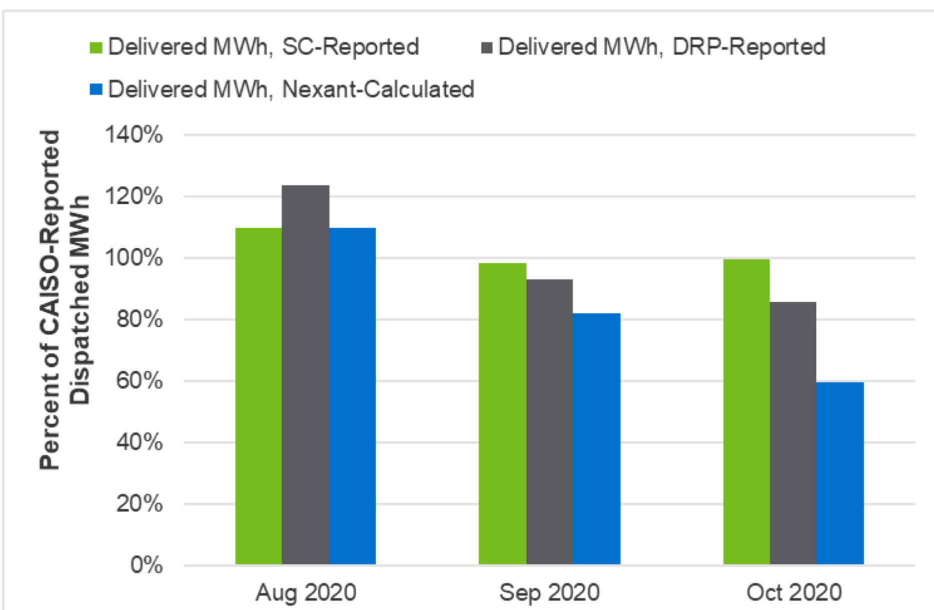
Figure 9-7 compares CAISO-reported dispatched MWh to SC-reported delivered MWh, DRP-reported delivered MWh, and Nexant-calculated delivered by month, for all *[REDACTED]* events that met Nexant's data requirements. In August, all delivered energy estimates are greater than the CAISO-reported dispatched energy, with Nexant-calculated and SC-reported energy being very similar, and DRP-reported being slightly larger. In September, all four values are very close, and range from identical CAISO-reported dispatched and SC-reported delivered to slightly lower DRP-reported energy and even lower Nexant-calculated delivered energy. In October, CAISO-reported dispatched and SC-reported delivered energy are nearly identical again, and DRP-reported delivered energy is slightly lower. Nexant-calculated delivered energy is even lower. Overall, *[REDACTED]* accurately reports its delivered energy and performs well compared to CAISO-dispatched energy.

Figure 9-7: Dispatched and Delivered MWh: *[REDACTED]*

[REDACTED]

Figure 9-8 presents SC-reported, DRP-reported and Nexant-calculated delivered energy as a percentage of CAISO-reported dispatched energy for all eligible *[REDACTED]* events by month. *[REDACTED]*'s Nexant-calculated delivered energy performs at 110% in August, 82% in September and at 59% in October, with decreasing performance over time.

Figure 9-8: Delivered Energy as a Percentage of Dispatched Energy: *[REDACTED]*



[REDACTED]

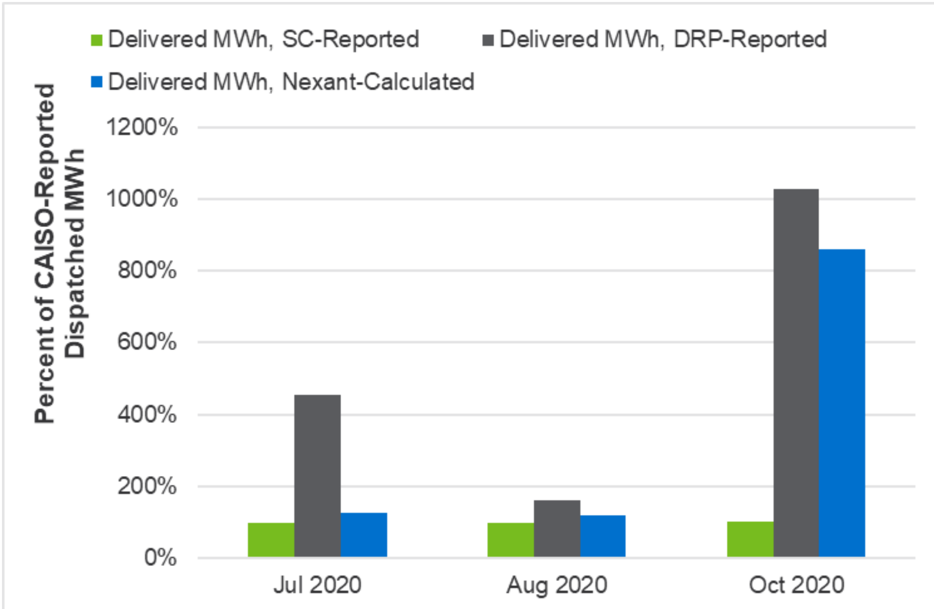
Figure 9-9 compares CAISO-reported dispatched MWh to SC-reported delivered MWh, DRP-reported delivered MWh, and Nexant-calculated delivered MWh by month for all *[REDACTED]* events that met Nexant's data requirements. In each month, the DRP overestimated its delivered energy compared to the Nexant-calculated and SC-reported delivered energy. The CAISO-dispatched and SC-reported delivered energy values are nearly identical, but consistently lower than the Nexant-reported delivered energy.

Figure 9-9: Dispatched and Delivered MWh: *[REDACTED]*

[REDACTED]

Figure 9-10 displays the three delivered energy calculations as a percentage of CAISO-reported dispatched energy for all eligible *[REDACTED]* events by month. In July and August, *[REDACTED]*'s Nexant-calculated delivered performed at around 100% while October over-achieved at 861% of CAISO-reported dispatched energy. In all three months, the DRP over-reported its delivered energy values.

Figure 9-10: Delivered Energy as a Percentage of Dispatched Energy: *[REDACTED]*



[REDACTED]

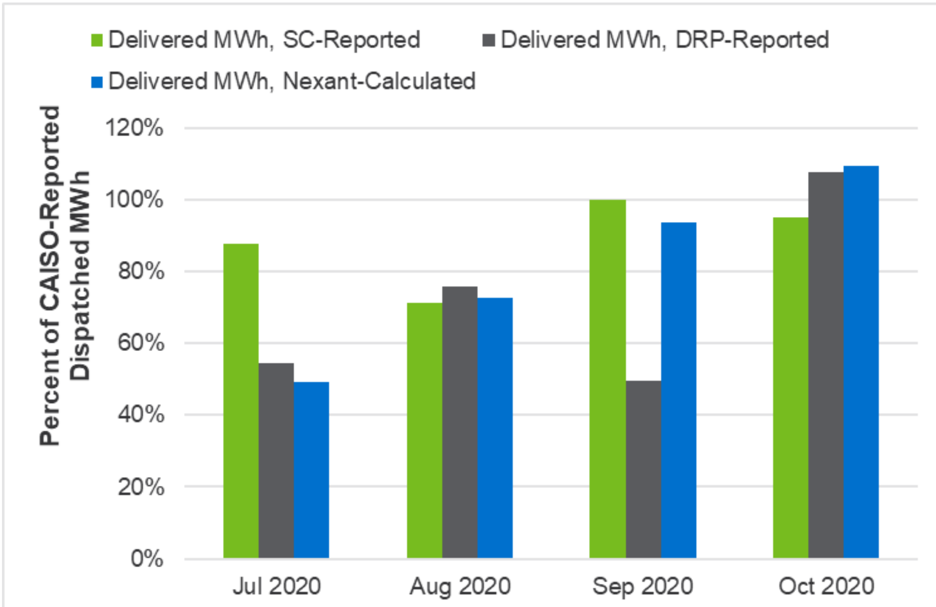
Figure 9-11 compares CAISO-reported dispatched MWh to SC-reported delivered MWh, DRP-reported delivered MWh and Nexant-calculated delivered by month, for all *[REDACTED]* events that met Nexant's data requirements. Overall, *[REDACTED]*'s estimates are very close in magnitude to those reported by the scheduling coordinators and those estimated by the Nexant Team. The DRP-reported and Nexant-calculated delivered energy estimates are particularly close, suggesting *[REDACTED]* is accurate in estimating its delivered energy for market dispatches.

Figure 9-11: Dispatched and Delivered MWh: *[REDACTED]*

[REDACTED]

Figure 9-12 displays SC-reported, DRP-reported, and Nexant-calculated delivered energy as a percentage of CAISO-reported dispatched energy for all eligible *[REDACTED]* events by month. *[REDACTED]* delivered close to 100% of its dispatched energy in September and October, while it fell short in July and August. Overall, *[REDACTED]*'s estimated dispatched energy was similar to Nexant-calculated dispatched energy. However, in September, DRP-reported dispatched energy was significantly lower than SC-reported delivered energy and the Nexant Team's calculation.

Figure 9-12: Delivered Energy as a Percentage of Dispatched Energy: *[REDACTED]*



[REDACTED]

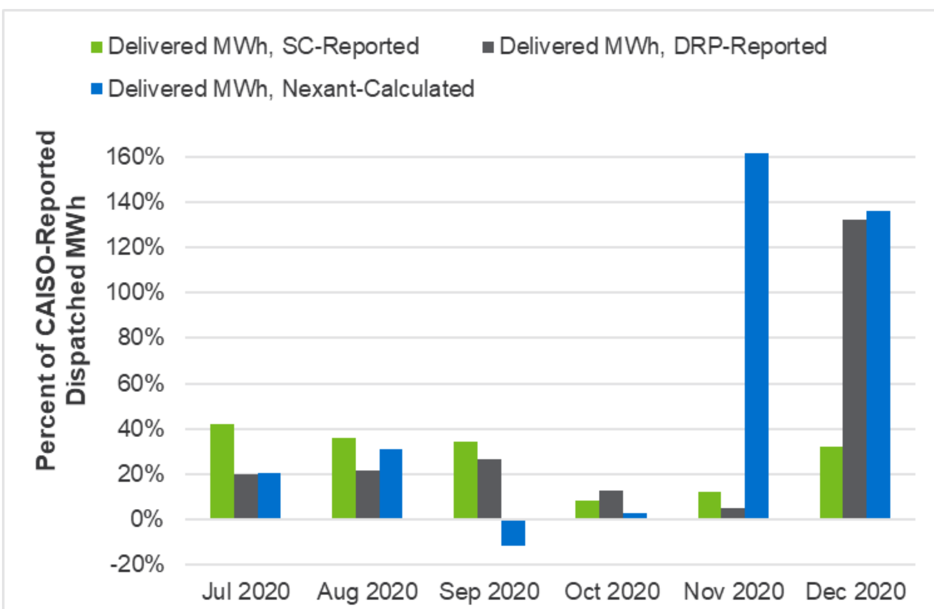
Figure 9-13 compares *[REDACTED]*'s CAISO-reported dispatched MWh to SC-reported delivered MWh, DRP-reported delivered MWh, and Nexant-calculated delivered energy for all available events by month. There are considerable discrepancies between the three delivered energy values in each month. In July, August, September, and October, *[REDACTED]* failed to meet CAISO-dispatched energy, and accuracy of DRP-reported delivered energy varied. In November and December, *[REDACTED]*-reported delivered energy exceeded CASO-dispatched energy but was significantly larger than Nexant's independently calculated delivered energy in November. In December and July, Nexant-calculated and DRP-reported delivered energy are nearly identical, indicating accurate reporting in those months.

Figure 9-13: Dispatched and Delivered MWh: *[REDACTED]*

[REDACTED]

Figure 9-14 displays SC-reported, DRP-reported, and Nexant-calculated delivered energy as a percentage of CAISO-reported dispatched energy for all available *[REDACTED]* events by month. *[REDACTED]* performance ranges greatly. Nexant-calculated delivered energy is equal to 20% in July, 31% in August, -12% in September, 3% in October, 162% in November, and 136% in December. In September, *[REDACTED]* customers aggregate event-hour usage was greater than aggregate baseline usage, leading to a negative delivered energy value. Nexant-calculated delivered energy is divided by CAISO's reported aggregate dispatched MWh in September, leading to performance of -12%.

Figure 9-14: Delivered Energy as a Percentage of Dispatched Energy: *[REDACTED]*



[REDACTED]

Figure 9-15 compares *[REDACTED]'s* CAISO-reported dispatched MWh, SC-reported delivered MWh, DRP-reported delivered MWh, and Nexant-calculated delivered for all available events by month. Note that *[REDACTED]* did not report metered, baseline or delivered energy values for their single July event, so there is no DRP-reported delivered MWh for July included in the figure. In both July and August, CAISO-reported dispatched energy is the same as SC-reported delivered energy. In August, Nexant-calculated delivered energy is slightly more than half of DRP-reported delivered energy.

Figure 9-15: Dispatched and Delivered MWh: *[REDACTED]*

[REDACTED]

Figure 9-16 displays SC-reported, DRP-reported, and Nexant-calculated delivered energy as a percentage of CAISO-reported dispatched energy for all eligible *[REDACTED]* events by month. *[REDACTED]*.

Figure 9-16: Delivered Energy as a Percentage of Dispatched Energy: *[REDACTED]*

[REDACTED]

[REDACTED]

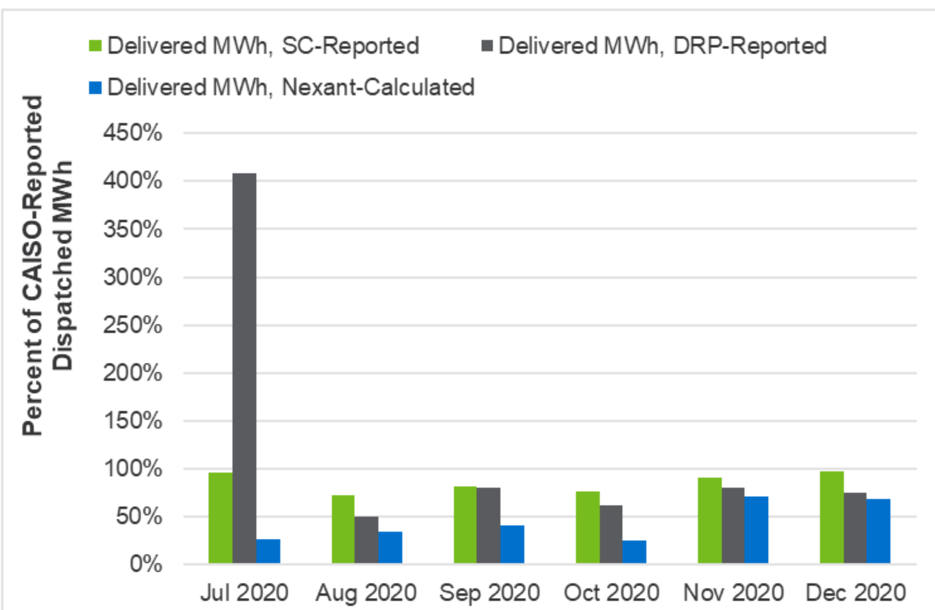
Figure 9-17 compares *[REDACTED]*'s CAISO-reported dispatched MWh, SC-reported delivered MWh, DRP-reported delivered MWh, and Nexant-calculated delivered MWh for all available events by month. In each month, *[REDACTED]* reports a higher delivered energy value than the Team's estimate. In July, *[REDACTED]* reported a value 4.5 times larger than the CAISO-reported delivered energy value, which likely indicates a reporting or measurement error in this month. The discrepancy in July is largely influenced by three events reported at *[REDACTED]* to *[REDACTED]* MWh by the DRP but calculated by Nexant as *[REDACTED]* to *[REDACTED]* MWh. *[REDACTED]* fails to meet the CAISO-reported dispatched energy value in each month as well, but comes close in November and December, months where fewer MWs were dispatched.

Figure 9-17: Dispatched and Delivered MWh: *[REDACTED]*

[REDACTED]

Figure 9-18 displays SC-reported, DRP-reported, and Nexant-calculated delivered energy as a percentage of CAISO-reported dispatched energy for all eligible *[REDACTED]* events by month. *[REDACTED]*'s performance ranges from 26% to 71%, improving through time. In July, the DRP-reported delivered energy is over 400% of CAISO-reported dispatched energy.

Figure 9-18: Delivered Energy as a Percentage of Dispatched Energy: *[REDACTED]*



Overall, DRAM's accuracy in reporting baselines, consistency across delivered energies and performance relative to CAISO dispatched energy is extremely variable by DRP and over time. Additionally, the Nexant Team found that in a majority of events, the DRP over-reported their delivered energy when compared to Nexant's calculation based on IOU AMI data. The DRPs must also use AMI data to calculate delivered energy and the two calculations are expected to be aligned. While there are concerns regarding the quality of IOU meter data[70], those concerns are not expected to introduce systematic bias in this analysis. Combining all DRPs together over represents the larger DRPs' performance and accuracy. *[REDACTED]* show relatively consistent SC-reported delivered energy, and DRP-reported energy. These *[REDACTED]* DRPs consistently perform and accurately calculate their baselines. *[REDACTED]*. *[REDACTED]* consistently over-reported its delivered energy, but also consistently out-performs its CAISO-reported dispatched energy. *[REDACTED]* is extremely variable in performance and accuracy of reporting. *[REDACTED]* overreports its delivered energy, but never meets its CAISO-reported dispatched energy. *[REDACTED]*'s delivered energy was negative in every month except for November 2020 and has very poor performance as a result. *[REDACTED]*'s accuracy in reporting its delivered energy varies from month to month. The variability in performance and accuracy can be partially attributed to data issues Nexant encountered with the various datasets used for this analysis.

9.5 Discussion

We observe that while DRAM performance appears to be improving year-over-year, there is still significant variation by DRPs and significant room to increase performance overall. The size of dispatch appeared to have no impact on performance.

From an event-based perspective, the DRPs are all capable of performing to CAISO's expectation though the data also shows variation among the DRPs. Additionally, there is still room for each DRP to improve the ability of performing at high levels more consistently, especially those DRPs that seem to be more active.

The performance level of DRAM resources may be impacted by a lack of incentive to consistently perform at or near expectation. From a CAISO market perspective, the only "penalty" a DRAM resource has if it does not reduce load by the amount expected based on CAISO dispatch instructions is to settle the difference at the RT energy price. While in some cases (e.g., when prices are high) this could result in a significant charge, compared to the revenues received from contracts, it may not be an effective incentive. Additionally, DRAM resources are paid based on invoices provided to the contracting party. The invoice only needs to show performance of one hour. Thus, so long as the DRP can show high performance during at least one hour, there is little additional incentive to consistently perform at the same level.

[70] See Section 10: Revenue Quality Meter Data Delivery

This portion of the analysis also aimed to assess the accuracy of DRPs baseline calculations by replicating the DRP's baseline methodology and presenting DRP-reported, SC-reported and Nexant-calculated delivered energy side by side.

Overall, the accuracy and performance of DRAM resources varies greatly by DRP and over time. In most event hours, DRPs overreport their delivered energy. In addition to this, DRPs do not report the same delivered energy values in their quarterly reports as they do when the SC reports the delivered energy to CAISO for settlement. *[REDACTED]* tend to more accurately report their delivered energy and more consistently meet their expected energy. *[REDACTED]* all differ in the accuracy of their baselines and performance of their resources through time.

9.6 Data Sources and Challenges

The Nexant Team utilized data from multiple sources in the Nexant-calculated delivered energy approach, event-based, and time-based performance analyses of DRAM. Data was gathered form the CAISO, each DRP, and each of the three IOUs. Throughout this project, Nexant had to manage, clean, and work with incomplete, inconsistent, erroneous, and duplicative data. Having to reconcile data across different data sources and datasets led to many inconsistencies in the data. Where possible, the Nexant Team worked internally and with relevant stakeholders to resolve data issues, but some could not be solved within scope. Nexant recorded the issues below to describe how data issues shaped the analyses and to explain how such issues could be avoided in the future. Note that the majority of issues described below apply to the Nexant-calculated delivered energy approach, while the CAISO data section applies to the time-based and event-based performance analyses as well.

9.6.1 CAISO Data

CAISO bid, scheduling, and settlement data received by the CPUC under a standard subpoena comprises the foundation of this analysis. Ten Demand Response Providers' (DRPs) contracts were evaluated across four years from January 2018 to May 2021. There were some challenges encountered in processing the data from the SC files, primarily in the form of missing or incomplete data. Significant amounts of intervals with either missing metered data or had meter data reading 0 MWh. Missing and zero values were omitted from the analysis. Therefore, CAISO metered values may be higher than reported if these are inaccurate readings.

Initially, the scope of the evaluation also included an assessment of how effective demand response resources were in being able to provide necessary ancillary services in the RTM. However, the CAISO bid, and settlement data provided did not include ancillary services. *[REDACTED]*. Thus, the evaluation report does not include an assessment of demand response resources providing ancillary services.

9.6.2 Quarterly report data

Nexant used the event data and resource characteristics from the DRPs' quarterly reports submitted to Energy Division. The first challenge faced by the Nexant Team was identifying DRAM events. An event is defined as expected energy greater than 0 MWh. The quarterly reports contained some inconsistent information such as: existence of a market award with no corresponding expected energy, existence of a non-zero expected energy but no corresponding market award, or instances of non-zero expected energy with no customers dispatched. Additionally, some assumed events reported in the quarterly reports (expected energy greater than 0 MWh) had missing or 0 MWh meter, baseline and delivered energy values, which are required to be reported when an event occurs. Using the quarterly reports, Nexant determined an event occurred if expected energy was greater than 0 MWh and was able to analyze it if at least one customer was dispatched and it had non-missing metered energy, baseline energy and delivered energy. Finally, the Nexant Team cross-checked this list of events with CAISO-reported dispatches. There were 442 event dispatches reported by CAISO that were not included in the DRPs quarterly reports. Additionally, some events reported by the DRPs quarterly reports did not show any expected energy values in the CAISO data.

9.6.3 DRP Enrollment Data

DRP-provided enrollment data was used to map customers to their respective DRAM resources during events. This data was critical for determining which customers to include in the Nexant delivered energy estimations because it identifies which IOU customers experienced which events. The enrollment data had several issues including missing data, data inconsistent with other data sources, and problematic duplicates. Enrollment data was sometimes missing customers, or entire resources. *[REDACTED]*. At times, customers included in the enrollment data were missing unique customer identifiers that were needed to map them to customer demographics and AMI data from the IOUs.

Additionally, some enrollment data from the DRPs included more customers enrolled in a resource than they reported were dispatched, making it impossible to tell which of the customers were dispatched during the event. *[REDACTED]*. Problematic duplicates arose when customer identifiers within the enrollment data did not uniquely identify customers and when the same customers were enrolled in multiple resources at the same time. In the latter case, the Team could not assume a customer was enrolled in one resource and not in the other.

9.6.4 IOU Customer Characteristics

Customer characteristics provided by the IOUs were used to map customers to additional identifiers included in the meter data and to determine the customer's class. This data included some duplicates where a given customer was assigned both residential and non-residential status and could not be used in the analysis. Some customers included in the DRP enrollment data were missing from IOU-provided demographic customer characteristics dataset. Typically, Nexant could still utilize these missing customers in the analysis by assuming their residential customer status from that of the resource they were registered to. But in the case of mixed resources where the resource has both residential and non-residential customers in it, residential status could not be assigned to the customer, and it was excluded from the analysis. *[REDACTED].*

9.6.5 AMI Data

AMI data provided by the IOUs was used to map DRAM customers to their hourly energy use and was key to the baseline analysis. Overall, this data was largely unproblematic, with only some missing meter data for a handful of customers. CAISO dictates that baseline analyses should be conducted at the five-minute interval, but the Nexant Team received hourly AMI data. Therefore, the baseline analysis was calculated at the hourly level instead of five-minute.

9.6.6 Baseline Methodology

In their quarterly report, DRPs reported which baseline methodology they used to calculate delivered energy for each event. The Team used the same methodology to calculate and recreate the baseline. In most cases, this data was readily available in the quarterly reports filled out by the DRPs. Sometimes, the methodology field was no filled out by the DRP but the Team was still able to assume which methodology was used based on the resource type (residential and non-residential) and DRP. Typically, a DRP only used one baseline method. In other cases, DRPs reported using the Combined method, but only dispatched residential customers on that event day or the Team only had available data for the residential customers it dispatched. Here, the Team used the Day Matching 5-in-10 method to evaluate these events, since the residential segment of a Combined analysis only utilizes the 5-in-10 method. According to the CAISO baseline methodology rules, outages are required to be excluded from the pool of baseline days. However, the Team did not receive the necessary outage data and was unable to exclude outage days.

9.6.7 Summary

The various data issues above resulted in decreased confidence in the reported values from DRP, IOU, and CAISO sources. Missing and problematic data on resources, customers, bidding, meter and settlement data narrowed the number of events the Nexant Team was able to analyze and decreased the accuracy of which the remaining were analyzed. Metered energy, which represents the aggregate energy used by a resource in each hour, was different in the DRP's quarterly reports, the CAISO's settlement data and the IOU-provided AMI data. This is important because the baseline analysis compares metered data to average baseline metered data. Comparing the same customer set during the same hours of the same day, should match across all three sources. Inconsistencies between DRP enrollment, IOU customer data, and DRP customers dispatched could also have a significant impact on the analysis. Due to various data issues, the Team cannot be fully confident that our analysis included the same customers that the DRPs did for a given event. Inconsistencies in contract identifiers between DRP and IOU sources impacted the Team's ability to evaluate the time-based and event-based portion of this analysis for all resources involved. As such, the Team only evaluated events where at least 95% of dispatched customers had sufficient data and no more than 100% of dispatched customers are present in the enrollment data. The Team estimated delivered energy for 71.3% of the event hours reported by the DRPs. Table 9-13 describes the number of events analyzed in Section 9.4 and for which reasons others were excluded. The most common reason events were excluded was that less than 95% of customers dispatched were available for analysis.

Table 9-13: Description of Events Excluded from Analysis, July-Dec 2020

Reason Excluded from Analysis	Number of Event Hours	Percent of Total Event Hours
Total Event Hours, during AAH, July-Dec 2020 per Quarterly Reports	**26,276**	**100%**
Holiday event	480	1.8%
Below 95% cutoff	4,829	18.4%
DRP did not report event- CAISO reported dispatch	442	1.7%
Enrollment > 100%	1,762	6.7%
DRP reported 0 customers dispatched	38	0.1%
Total Event Hours Analyzed	**18,725**	**71.3%**

Holidays, weekends, and hours outside of the AAH window were also excluded.

10 Revenue Quality Meter Data Delivery

Revenue Quality Meter Data (RQMD) is critical for ensuring a functional monitoring and reporting process, so it is important to have a governance structure that results in timely data delivery. D.19-12-040 authorized a Working Group (WG) to discuss and develop a report investigating a series of questions regarding delayed customer and meter data that the Utilities provide to DRPs so that they may participate in the CAISO wholesale market. The WG report was published in May 2021 and is included in Appendix A. For this evaluation, The Nexant Team was tasked with reviewing this report and based on its findings, providing a recommendation as to whether to impose penalties to the IOUs for delayed, missing, or inaccurate RQMD.

10.1 Summary of Findings from Working Group Report

10.1.1 DRP Comments

Five DRPs that had contracts in 2020 submitted responses to a questionnaire about the frequency and impact of delayed RQMD from each IOU. They were asked to provide details of the financial and operational consequences of missing or delayed RQMD.

In PG&E's territory, DRPs reported not receiving RQMD by the T+48B (48 business days from the relevant trading day) deadline for 1% to 5% of accounts. Of greater concern than delays are data missing for longer than a week, or solar export data being double counted for extended periods of time.

SCE's territory was reported as having the most data delays and quality issues compared to the other IOUs. Two DRPs reported they did not receive any RQMD for 1% to 5% of customers. Several DRPs reported issues of inaccurate data due to time-shift issues, which are more impactful than delayed data delivery. Another DRP said for a list of approximately 380 customers, they identified 140 quality issues across six months of data, including 30 instances of missing data.

In SDG&E's territory, the DRPs reported not receiving RQMD by the T+48B deadline for 1% to 5% of accounts. Two DRPs said data delays are uncommon with SDG&E and are not as significant of an issue compared to the other IOUs.

The DRPs described many procedural and financial consequences of delayed or missing RQMD. Data delivery delays prevent the calculation of customer performance, which impacts revenues and delays payments to customers, lowering satisfaction with the program. Data delays also impose the risk of CAISO penalties and impact the creation of supply plans. In many cases, DRPs spend significant time and resources tracking down missing data or developing internal solutions to overcome these issues.

While four of the five DRPs reported not losing capacity payments because of missing or delayed data, some reported delays in invoicing or forfeiture of a portion of payment due to erroneous (time shifts) or missing data lowering their performance. Some DRPs also reported losing revenue from the energy market due to missing or delayed data. Another potential concern is that missing or inaccurate data will prevent DRPs from knowing if they have met the 30 MWh per MW minimum requirement. This lack of visibility could result in them having to dispatch additional hours as a buffer against a potential delivered energy penalty.

10.1.2 IOU Comments

All three IOUs submitted responses to a questionnaire about the processes and timelines for Validation, Editing, and Estimation (VEE) of raw data as well as the causes of missing or delayed RQMD.

PG&E said they collect and transfer meter data to their Meter Data Management System (MDMS) every four hours. The meter data is validated three times per day before transferring to billing and their data warehouse. RQMD is available after the completion of a billing cycle for each service account, which is approximately 30 days. The DRPs are required to have API capability to retrieve RQMD from PG&E's systems. PG&E provided several causes of missing or delayed data, including non-communicating and malfunctioning meters, closed service accounts and data sharing authorizations, IT system and application outages, and a misunderstanding by third parties of the pre- and post- RQMD status in the Share My Data platform.

SCE said they collect meter data daily and immediately transfer to their MDMS. They also validate the data daily before it is transferred to their data warehouse. RQMD is available after the completion of a billing cycle for each service account, which ranges from 27 to 33 days. RQMD is shared with DRPs four days after the account is billed. SCE said the primary causes of missing or delayed data include malfunctioning meters, missing or incomplete meter data, meter configuration changes, delays in receiving customer data updates, need for account updates due to rate or program changes, and data validation procedures based on a customer's rate and historical usage.

SDG&E also collects meter data once per day and immediately sends it to their MDMS. The data is validated and transferred to billing in two batches twice per day. RQMD is available daily and can either be sent to DRPs or they can retrieve it through an API. SDG&E said the primary causes of data delivery delays are non-communication and malfunctioning meters, closed service accounts and data sharing authorizations, access issues, and back-office challenges.

10.2 Discussion

Missing and delayed RQMD has many negative impacts for both the DRPs and their customers. Many of the concerns raised in the WG report were echoed in interviews with the DRPs conducted by the Nexant Team (see Section 4.4) In those interviews, DRPs said missing or inaccurate data is one of, if not the most significant challenge faced while participating in the program due to the number of financial and procedural consequences. Rules and procedures should be implemented to reduce the frequency and impact of missing and delayed data to allow DRAM to continue to grow and succeed in the future.

Based on the findings from the WG report and our own in-depth interviews with DRPs, the Nexant Team does not recommend any retroactive penalties be imposed to the IOUs due to the lack of an existing framework and agreement for financial implications. However, the Team believes metrics should be established to define the success or failure of delivery of RQMD that come with either penalties if they are not met, or a financial earnings opportunity if they are met. These metrics could include (but are not limited to) the time to deliver RQMD, accepted data formats and which data elements are provided, and data accuracy.

For PG&E and SCE, RQMD is available after data validation at the end of the customer's billing cycle. RQMD is available after data validation daily in SDG&E territory. The Nexant Team recommends PG&E and SCE make RQMD available immediately after validation rather than waiting until the end of the billing cycle. Since IOU programs report results to CAISO within a few days after each DR event, regardless of billing cycle, the data should be available for DRAM in the same timeline. This could reduce the wait for RQMD to be available by several days or even weeks and prevent or reduce the impact of many consequences described above.

The Team also recommends that quantifiable revenue loss or fines incurred by the DRPs due to delayed or inaccurate RQMD should be reviewed in a hearing by a neutral arbiter to determine percent culpability and negligence (to only things within the IOUs' control – not for things that cannot be solved) whenever issues cannot be resolved between the DRP and IOU. Further, the timeline for revenue loss or penalties to DRPs should be adjusted based on data delivery date, not conclusion of program months.

11 Recommendations

While DRAM has demonstrated some improvements following the 2019 CPUC evaluation and recent changes in DRAM requirements, several fundamental issues have persisted, including:

- Widely varying performance, and consistent underperformance in some cases, have significantly lowered the overall effectiveness of DRAM
- Lack of availability during critical hours, such as the August 2020 heatwave, as studied in more detail in the CAISO DMM report[71]
- Given the above two issues, the additional system capacity (if any) that each DRP has delivered is highly uncertain and varies substantially
- Data errors and reporting inconsistencies, leading to over-compensation and a lack of confidence and transparency regarding the overall performance of DRAM
- Significant administrative burden for all parties involved

In this section, the Nexant Team provides several recommendations to help address these fundamental issues.

Performance Incentives

Align incentives of DRAM capacity contracts with demonstrated performance, including consistency and availability, and unique characteristics of DR.

The DRAM evaluation shows that the performance (i.e., ability of DRAM resources to provide the load reduction expected by the CAISO market) has much room for improvement. From a reliability perspective, the CAISO market relies on resources providing the energy in accordance with the dispatch instructions. The wide array of performance between DRPs, and even between events for each DRP, introduces a reliability concern and uncertainty for CAISO market operators. They are unsure if and when DRAM resources will be able to meet their schedule, which can potentially lead to taking other measures to ensure reliability of the market as a whole.[72] Effectively, this means that the resource is not delivering the additional system capacity that is it contracted for as part of DRAM.

There does not appear to be an effective incentive in place to ensure consistently high performance from DRAM resources. From a CAISO market perspective, the only “penalty” a DRAM resource has if it does not reduce load by the amount expected based on CAISO dispatch instructions is the settlement of energy. The settlement is based on the metered data

[71] The CAISO DMM report titled “Demand response issues and performance” found that a major issue for the August 2020 heatwave was that a substantial portion of DR resources, both utility and third-party, was not available to be dispatched in real-time during critical hours. The Nexant Team did not thoroughly investigate this availability issue, given data limitations and the scope of the six criteria for this evaluation, but it is important to consider for these recommendations.

[72] For example, operators have the ability to issue commitment and dispatch instructions outside of the market for reliability reasons or adjust the load used in the market.

provided to the CAISO by the Scheduling Coordinator and the baseline. In other words, they are only paid for what is provided, not what was expected to be provided. Additionally, DRAM resources are paid based on invoices provided to the contracting party. The invoice only needs to show performance of one event. Thus, so long as within each month the DRP can show high performance during at least one event, there is little additional incentive to consistently perform at the same level.

Furthermore, the typical RA contract works well for traditional thermal generation that has a fairly consistent capacity throughout the year and is fully available after a plant goes into operation, other than rare forced outages and planned outages for maintenance during off-peak periods. This construct does not apply to DR resources, which require several months to ramp up participation, have varying capacity throughout the day, week and year (due to business operating hours and weather sensitivity) and may not perform well or be available on a quick-start basis. All of these factors require a revised DRAM capacity contract that incentivizes DR resources to perform best and be available when they are needed most.

Therefore, the Nexant Team suggests examining the following changes to the DRAM capacity contracts:

- Provide an upfront incentive to support ramping up DR participation, but withhold a majority of the capacity payment each year to allow time for the DRP to demonstrate consistently high performance and availability during the peak season when DR is most needed (May through October)
- Tie the performance-based payment to an adjusted capacity metric, such as the Effective Load Carrying Capacity (ELCC), which accounts for variation in performance and availability, especially during critical hours
- Include clear criteria for early contract termination and penalties if a given resource is shown to consistently underperform[73]
- Eliminate any form of capacity compensation based on bid amounts, such as the Must Offer Obligation (MOO), which has been shown to loosely reflect performance and demonstrated capacity based on actual dispatches
- Incentivize aggregation of resource IDs within each subLAP to reduce statistical noise in baseline calculations, allowing for a more accurate assessment of a given DRP's ability to perform consistently
- If the above recommendations are implemented, consider a multi-year contract with annual performance-based payments and a ramp-up period to allow time for the resource to grow to full capacity

[73] The IOUs should factor historical performance by DRPs in subsequent DRAM solicitations as well, up to and including disqualification of consistent underperformers.

While an ex ante method to validate capacity and compensate for it would be preferred, the experience of DRAM has shown that an ex post approach is much more reasonable, given the unique characteristics of DR. Nonetheless, these recommended changes would still give DRPs the flexibility to bid into the CAISO market as they see fit. If a given DRAM resource shows that it is available, competitive and effective during critical hours, then larger capacity incentives are earned.

Data Accuracy and Administrative Burden

Develop centralized data repository and reporting system to increase data accuracy, prevent over-compensation and reduce administrative burden.

Missing, delayed, inconsistent and problematic data provided sizeable barriers to conducting this evaluation and showed that the DRPs frequently reported different results for the same performance metric that the Nexant Team calculated. These issues also showed that some DRPs may have been significantly over-compensated. The Nexant Team found that in a majority of events, the DRP over-reported their delivered energy when compared to Nexant's calculation.

To address these issues, incentives or penalties could be established to ensure accurate and timely data deliveries. The IOUs could also conduct more frequent audits of the underlying data in DRAM invoices. However, these types of measures would only increase the administrative burden that has already become a major issue for all parties involved. For DRPs in particular, additional administrative burden would most likely lead to further market consolidation, which goes against one of the key objectives of DRAM.

Instead, this recommendation focuses on developing a solution that will help reduce administrative burden while addressing inaccuracies in data, reporting and invoicing. The key underlying issues are that the various parties are managing, analyzing, and reporting the same data in different ways and there isn't a "single source of truth" for all DRAM data. This includes utility meter data, DRP enrollments mapped to utility accounts, contract-level and resource-level information, bids into the DA and RTM, and data relating to market dispatches and capacity tests (both raw data and subsequently modified datasets that support reporting). Integrating third-party DR into the CAISO market requires all of this granular information from different parties.

Therefore, the Nexant Team recommends developing a centralized data repository and reporting system to address these issues by ensuring consistent customer, event and DRP enrollment data and reporting across CAISO, the IOUs, and the DRPs. The repository can serve as the single source of truth for all DRAM data, with strong data security and governance measures in place to ensure that each party is only allowed access to the data that they should see. It would also help the CPUC continuously monitor, evaluate, and forecast DR performance to ensure further transparency and track available capacity.

This evaluation, including the public quarterly reports, has laid substantial groundwork in identifying the required data and how to consistently calculate important metrics relating to the performance of DRAM. However, it took the Nexant Team nearly a year of consistent effort to release the first publicly available quarterly reports, requiring numerous iterations with DRPs to finalize the data and calculations in some cases (and even then there was uncertainty regarding validity of data). Without automating these processes and having a system to monitor data quality on an ongoing basis, the data errors, reporting inconsistencies and lack of transparency will almost certainly persist.

Comparing DRAM to other DR Resources

Conduct a cost-effectiveness analysis of DRAM to compare to IOU DR programs and LRAC based on historical performance.

Criterion 3 assesses the competitiveness of the 2019-2021 DRAM (IV-VI) auctions on an internal basis, using benchmarks of bid dispersion, in addition to external competitiveness with other IOU DR program resources and IOU and statewide system generation capacity resources. These various points of comparison for DRAM bid prices are valuable, particularly if they are evaluated annually or periodically as part of monitoring DRAM performance.

The Nexant Team recommends that a full cost-effectiveness analysis using both DRAM program costs and DRAM program benefits be conducted. This analysis should also factor in the actual performance of DRAM resources to derate bids and compare those adjusted bids to LRAC. After considering the widely varying performance of DRAM resources, the cost of demonstrated capacity based on actual dispatches may be higher than LRAC. This cost-effectiveness analysis will enable stakeholders to assess the net benefits or costs of DRAM in direct comparison to the net benefits or costs of other IOU DR programs, including third-party DR resources that the IOUs manage (such as CBP). The analysis may find that the IOU-managed programs are a more cost-effective avenue for increasing third-party DR participation.

CAISO Market Availability

Further evaluate the impact of minimum load costs, start-up times and market rules on resource availability and market dispatch.

Even if a DRP is bidding incremental energy offers at competitive prices, it may still not be utilized by the market if the commitment costs and start up times make it either uneconomical or unavailable in the market. The present evaluation was unable to confirm what commitment costs were reflected in the market based on the data provided. Additionally, it would be more effective to have more recent and frequent snapshots of the Masterfile data in order to confidently evaluate the portion of DRAM resources classified as long-start resources.

Lastly, based on the available Masterfile data, there seem to be a significant portion of demand response resources with less than 1 MW of capacity. Per the CAISO's existing rules, these demand response resources would be considered exempt from the CAISO's incentive mechanism for RA resources to make themselves available to the market (via market bids) – the Resource Adequacy Availability Incentive Mechanism (RAAIM). Thus, there is no penalty for DRAM resources less than 1 MW for not being available to the market during the RA Must Offer

Obligation hours. More recent and frequent Masterfile data would allow for a more comprehensive evaluation of the portion of DRAM resources exempt from RAAIM.

Performance Calculation Methodology

Assess and consider offering other choices in baseline methodology that better represent demand response performance for certain customers.

Many DRPs spoke about how the current 10-of-10 baseline methodology does not accurately represent performance and hope to see other CAISO-approved baseline approaches available for certain customers, especially those with irregular or highly weather-dependent load patterns or those that operate only four days a week. The Nexant Team recommends assessing the accuracy of other baseline methodologies and determine which customer types, technologies, or weather conditions would be better represented by alternative performance calculation approaches, including the use of control groups.

The Team also recommends investigating the potential risks and benefits of allowing DRPs to use the Meter Generator Output (MGO) protocol for battery storage, electric vehicle chargers, or other sub-metered technologies rather than relying on traditional meter data to quantify performance.

Revenue Quality Meter Data (RQMD)

Consider establishing specific metrics regarding delivery timeline and data accuracy to define the success or failure of delivery of RQMD with either financial incentives for meeting the requirements or penalties if they are not met.

According to a number of DRPs interviewed during our evaluation, delayed, missing, and inaccurate RQMD is one of the most significant barriers to participation in DRAM. There are several financial and procedural consequences due to these data challenges, including potential loss of revenue and fines, lowered performance, less accurate supply plans, and additional time spent tracking down and correcting data. In many cases, DRPs are late in submitting invoices or quarterly reports solely because they do not have the data necessary to complete these tasks.

The Nexant Team recommends that quantifiable revenue loss or fines incurred by the DRPs resulting from delayed or inaccurate RQMD should be reviewed in a hearing by a neutral arbiter to determine percent culpability and negligence. The timeline for revenue loss or penalties to DRPs should be adjusted based on data delivery date, not conclusion of program months.

The Team also recommends that the IOUs make RQMD available for DRAM immediately after validation rather than waiting until the end of the billing cycle, preventing, or reducing the severity of various financial or procedural consequences. The RQMD transfer process could also benefit from a centralized data repository to track and monitor data quality, as recommended above, helping to reduce administrative burden for the IOUs and DRPs.

Appendix A   Revenue Quality Meter Data (RQMD) Working Group Report

RQMD Working
Group Report PUBLI

Now a part of Resource Innovations

719 Main St.

Half Moon Bay, CA 94019

Tel: (415) 369-1000

Fax: (415) 369-9700

www.nexant.com

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