Proceeding: R.20-11-003

Exhibit No.: SDGE-12

Witness: Jenell McKay

PREPARED PHASE 2 REPLY TESTIMONY OF SAN DIEGO GAS & ELECTRIC COMPANY REGARDING PROPOSALS FOR INCREASING SUPPLY DURING PEAK AND NET PEAK DEMAND HOURS THROUGH ADDITION OF UTILITY-OWNED RESOURCES

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

September 10, 2021

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PREPARED PHASE 2 REPLY TESTIMONY OF SAN DIEGO GAS & ELECTRIC COMPANY REGARDING PROPOSALS FOR INCREASING SUPPLY DURING PEAK AND NET PEAK DEMAND HOURS THROUGH ADDITION OF UTILITY-OWNED RESOURCES

I. INTRODUCTION

The purpose of this reply testimony is to respond to parties' opening testimony submitted in Phase 2 of the instant proceeding on the issue of utility-owned energy storage resources, as well as to respond to the proposal by the Microgrid Resources Coalition (MRC) for an Emergency Capacity Services Tariff.

In its Phase 2 opening testimony, SDG&E offered a proposal intended to bring new energy storage resources online quickly and requested issuance no later than September 15, 2021 of a Commission ruling laying the groundwork for expedited negotiations regarding such resources and approval through a Tier 2 Advice Letter (AL) process.[1] Under SDG&E's proposal, its Utility Development Team (UDT) function (which is separate from its energy/capacity supply function) would be directed to follow a streamlined process to seek approval for energy storage projects that could be brought online in the very near term, with costs to be recovered through a new non-bypassable charge (NBC) along the lines of that proposed by Commission staff in the Staff Paper.[2] SDG&E submits that this expedited process is warranted given the current reliability emergency faced by the State. As discussed below, parties' opening testimony largely supports this conclusion.

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[1] *Prepared Phase 2 Direct Testimony of San Diego Gas & Electric Company Regarding Proposals for Increasing Supply During Peak and Net Peak Demand Hours Through Addition of Utility-Owned Resources*, dated September 1, 2021 (Phase 2 Opening Testimony of SDG&E/Utility-Owned Resources - McKay), p. 6.

[2] *Id*. p. 8.

In addition, SDG&E explains below that MRC's proposal for a new Emergency Capacity Services Tariff (ECST) or an ECST rate schedule under the Rule 21 tariff is outside of the scope of the instant proceeding. In addition, it is not feasible to develop a complete record in the instant case related to MRC's proposal in advance of issuance of a Commission decision in November. MRC's proposal should instead be considered in the Commission's Microgrid proceeding or the High Distributed Energy Resource (DER) proceeding.

II. SWIFT COMMISSION APPROVAL IS REQUIRED TO MEET EMERGENCY SUPPLY NEEDS

Parties' opening testimony reflects broad agreement that new reliability resources must be built as quickly as possible and that the Commission and stakeholders must move beyond 'business as usual' approaches to consider creative solutions for easing the State's reliability challenges. For example, California Energy Storage Alliance (CESA) observes that the "Commission needs to consider new frameworks and approaches to standardize and fast-track their procurement and contract approval,"[3] pointing out that "the 'old way of doing things' when it comes to procurement and contract approval cannot be continued."[4] Similarly, Wartsila North America, Inc (Wartsila) warns that "the Commission cannot treat procurement as a 'wait-and-see' decision. Delays in decision making could mean that scarce inventory is procured in other markets and no longer available to California."[5] SDG&E strongly agrees.

To preserve grid reliability within the state, it is critical that the Commission pursue *all* available avenues for bringing new reliability resources online. It is equally important that the

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[3] *Opening Testimony of Jin Noh on Behalf of the California Energy Storage Alliance*, dated September 1, 2021 (Phase 2 Opening Testimony of CESA), p. 9.

[4] *Id*. at p. 10.

[5] *Opening Testimony and Proposals of Dr. Karl Meeusen on Behalf of Wärtsilä North America, Inc.*, dated September 1, 2021 (Phase 2 Opening Testimony of Wärtsilä), p. 5.

Commission provide necessary direction and regulatory approvals _as soon as possible._ If project developers are to expedite the deployment of additional resources and also ensure that 2022 *and* 2023 online dates are feasible, projects must begin development almost immediately. To be sure, achieving a 2022 online date will be a challenge and will require swift action by the Commission. For example, CESA suggests that a timeline involving submission of contracts for Commission approval via a Tier 1 AL by January 15, 2022, with final Commission approval by February 25, 2022 could allow for resources to meet a 2023 online date,[6] however that timeline, while expedited, would likely not be sufficient to allow projects to meet a 2022 online date. In certain cases, a Notice to Proceed (NTP) must be issued to developers by **November 1, 2021**, to ensure that a 2022 commercial online date for new energy storage resources can be met, as SDG&E explained in its opening testimony.[7] Given the significant time constraints that characterize the current situation, SDG&E's utility ownership proposal is intended to streamline and accelerate the Commission approval process to allow the earliest possible commercial online date for new projects.

SDG&E notes that Southern California Edison Company (SCE) offers a utility ownership proposal similar to SDG&E's and requests that the Commission issue an immediate directive to the investor-owned utilities (IOUs) to develop and install utility-owned storage resources.[8] SDG&E agrees with SCE regarding the potential reliability benefits of utility-owned resources and reiterates that Commission guidance must be issued *immediately* to support projects coming online in 2022 and 2023. Likewise, as SDG&E explained in its opening testimony and as Pacific

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[6] Phase 2 Opening Testimony of CESA, p. 16.

[7] Phase 2 Opening Testimony of SDG&E/Utility-Owned Resources – McKay, p. 2.

[8] *Direct Testimony of Southern California Edison Company* – Phase 2, dated September 1, 2021 (Phase 2 Opening Testimony of SCE), p. 59.

Gas and Electric Company (PG&E) also points out, an expedited contract approval process is absolutely necessary to bring resources online for 2022 and 2023. Thus, the Commission should maintain the approach adopted in Phase 1 for utility-owned resources and continue use of a Tier 2 AL process for utility-owned resources that enhance the state's reliability, climate, and affordability goals.[9]

III. THE COMMISSION SHOULD PURSUE ALL OPTIONS FOR DEVELOPING NEW ENERGY STORAGE RESOURCES NEEDED IN 2022 AND 2023

In discussing the proposal included in the *Energy Division Staff Concept Paper* (Staff Paper)[10] related to development of IOU-owned energy storage at IOU substations, the Independent Energy Producers Association (IEP) urges the Commission to "broaden consideration to other [non-IOU] sites that share similar attributes with substations regarding site control, ease of interconnection, and deliverability."[11] SDG&E agrees with IEP's basic premise that the Commission should not establish an ownership preference; that is to say, the Commission should not, as IEP suggests, prefer utility ownership of energy storage assets over independent ownership and likewise should avoid the reverse situation of a preference for independent ownership of energy storage resources over utility ownership of such resources. Instead, the Commission should consider *all* avenues for bringing new energy storage resources online as quickly as possible – in doing so, it should focus on identifying the pathways most likely to bring projects online within the 2022-2023 timeframe and should avoid disparate

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[9] *See Pacific Gas and Electric Company Emergency Reliability Order Instituting Rulemaking Errata Testimony*, dated September 1, 2021 (Phase 2 Opening Testimony of PG&E), Chapter 9, p. 9-10.

[10] *Energy Division Staff Concept Paper* dated August 16, 2021.

[11] *Prepared Testimony of Scott Murtishaw on Summer 2022 and 2023 Reliability Enhancements on Behalf of the Independent Energy Producers Association*, dated September 1, 2021 (Phase 2 Opening Testimony of IEP), p. 7.

treatment of otherwise equivalent projects solely on the grounds that one is utility-owned, and the other is not.

As a practical matter, the State will likely require *all* reasonable solutions available to it to address the current state of emergency related to grid reliability. The California Energy Commission's (CEC) 2022 Draft Preliminary Stack Analysis makes clear that a significant capacity shortfall exists within the State, and that additional resources are needed in the near-term to provide electric system resilience.[12] This means that the Commission should not discard any potential solutions and should instead allow parties to pursue *all* viable means of bringing new resources online as quickly as possible. This 'all hands on deck' approach is reflected in the Emergency Proclamation signed by Governor Newsom (Emergency Proclamation)[13] as well as in the *Assigned Commissioner's Amended Scoping Memo and Ruling for Phase 2* (Amended Scoping Memo), which acknowledges that potential reliability solutions include development of new reliability resources by *both* IOUs and third-parties through expedited processes.[14]

IV. BENEFITS OF UTILITY-OWNED RESOURCES

CESA points out that energy storage resources have represented the "largest source of incremental and/or replacement clean capacity in the near and long term."[15] Thus, energy storage are likely to play a primary role in addressing the current reliability crisis, which means that the Commission should consider *all* viable energy storage projects capable of providing

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[12] *California Energy Commission Draft Preliminary 2022 Summer Supply Stack Analysis* (2022 Stack Analysis), p. 4.

[13] *See* Executive Department State of California, *Proclamation of a State of Emergency*, dated July 30, 2021. Available at: https://www.gov.ca.gov/wp-content/uploads/2021/07/Energy-Emergency-Proc-7-30-21.pdf; *see also* Amended Scoping Memo, p. 2.

[14] Amended Scoping Memo, p. 4.

[15] Phase 2 Opening Testimony of CESA, p. 9.

reliability benefits in 2022 and 2023 regardless of whether utility-owned or independent, as discussed above. Middle River Power (MRP) challenges this conclusion, suggesting that the Commission should approve utility ownership of energy storage resources only if utility ownership "would be the only way to overcome challenges that would be faced by other developers and is in the best economic interest of the ratepayers."[16] MRP provides no clear rationale for this recommendation.

At a recent stakeholder workshop to discuss its preparation of an Energy Storage Procurement Study at the behest of the Commission, Lumen Energy Strategy (Lumen),[17] indicated that "more than 80% of storage capacity [has been] procured under 3rd-party contracts" and that "utility-owned projects account for 10% of storage procurement (~400MW)."[18] Thus, it is beyond dispute that that vast majority of energy storage projects are independently-owned and that utility ownership poses no material threat to competition within this market segment. MRP's suggestion that the Commission should ignore potential reliability solutions solely because they are proposed as utility-owned ignores the severity of the current crisis and the explicit direction of the Governor and the Commission to parties to 'turn over every rock' to identify additional supply options.

Moreover, utility ownership may confer benefits that are not available in many energy storage transactions with third party-owned resources. The data presented by Lumen indicate

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[16] *Prepared Testimony of Brian D. Theaker on Behalf of Middle River Power LLC*, dated September 1, 2021 (Phase 2 Opening Testimony of MRP), p. 22.

[17] D.13-10-040 requires the Commission to conduct a comprehensive evaluation of the Commission's Energy Storage Framework and energy storage procurement in compliance with Assembly Bill 2514. The Commission has retained Lumen to support this effort. *See* Lumen Presentation attached hereto as Attachment A, Slides 5 and 8.

[18] Lumen Presentation, Slide 16.

that most third-party contracts for energy storage are limited to “RA only” meaning that the “utility buys resource adequacy (RA) capacity and counterparty retains all other attributes including energy and ancillary services.”[19] By contrast, benefits of utility-ownership include RA capacity *and* energy and ancillary services, as explained in SDG&E’s opening testimony.[20] Additional benefits of utility-owned resources are obtained in the administration of the utility’s portfolio of resources, particularly when it comes to dispatching them into the California Independent System Operator (CAISO) market, where the utility must follow the Standard of Conduct 4 (SOC 4), adopted by the Commission in D.02-10-062 and further discussed in D.02-12-069, D.02-12-074, D.03-06-076, and D.05-01-054, which directs that “[t]he utilities shall prudently administer all contracts and generation resources and dispatch the energy in a least cost-manner.”[21]

In addition, MRP’s assertion that “IOU projects still face the same interconnection, deliverability, permitting and supply chain issues faced by any other developer,”[22] is not entirely accurate. While utility-owned projects may face some of the same challenges as third party-owned projects (*e.g.*, supply chain issues), projects sited on utility-owned land avoid other major hurdles (*e.g.*, permitting) faced by third-party projects. As previously explained by SDG&E, it is generally the case that development on sites owned or controlled by an IOU allows for an expedited construction schedule as compared with non-IOU properties where additional time is required for land acquisition and permitting.[23] The Staff Paper points out that IOU-owned sites

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[19] Lumen Presentation, Slide 16.

[20] Phase 2 Opening Testimony of SDG&E/Utility-Owned Resources – McKay, pp. 8-9.

[21] D.02-10-062, p. 52, Conclusion of Law (COL) 11.

[22] Phase 2 Opening Testimony of MRP, p. 22.

[23] Phase 2 Opening Testimony of SDG&E/Utility-Owned Resources - McKay, p. 3.

"can often avoid or expedite many of the challenges associated with bringing new projects online (*e.g.*, site control, interconnection, deliverability, permitting, etc.) . . ."[24] Similarly, PG&E observes that "[w]hile the process of building and deploying new resources still involves significant uncertainty, especially in light of constraints imposed by the ongoing COVID-19 pandemic, . . . new utility-owned storage may have a higher chance of coming on-line by the summers of 2022 and 2023."[25] SCE likewise notes that "[t]he IOUs may be able to develop, construct, and install utility-owned storage resources quickly by utilizing existing IOU substations that can avoid or expedite the challenges associated with new projects (*e.g.*, site control, permitting, interconnection, etc.).[26]

Thus, the suggestion by MRP that there are no instances in which utility ownership provides a unique benefit is erroneous. More to the point, however, the suggestion by MRP that viable energy storage projects should be prohibited or denied simply because they are proposed as utility-owned is unreasonable and wholly at odds with the clear direction provided in the Governor's Emergency Proclamation and in the Commission's Amended Scoping Memo. Put simply, the State needs *all* new projects capable of providing incremental capacity to come online as quickly as possible. Hence, the Commission should adopt SDG&E recommendation to permit its UDT to submit proposed energy storage projects directly to the Commission and should issue a ruling no later than September 15, 2021, establishing this pathway, as discussed in SDG&E's opening testimony.[27]

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[24] Staff Paper, p. 23.

[25] Phase 2 Opening Testimony of PG&E, Chapter 9, p. 9-10.

[26] Phase 2 Opening Testimony of SCE, p. 58.

[27] Phase 2 Opening Testimony of SDG&E/Utility-Owned Resources - McKay, p.4.

V. MRC'S EMERGENCY CAPACITY SERVICES TARIFF PROPOSAL SHOULD NOT BE CONSIDERED IN THIS PROCEEDING

MRC proposes Commission adoption of a new tariffed program, the Emergency Capacity Services Tariff (ECST),[28] while also separately suggesting creation of an ECST rate schedule under the Rule 21 tariff.[29] MRC's proposal falls outside of the scope of the instant proceeding and should not be considered by the Commission here; MRC's proposal should instead be considered in the Commission's Microgrid proceeding[30] or the High DER proceeding.[31]

According to the Amended Scoping Memo, the instant proceeding will consider "[r]ate structures, including pilot rates ***introduced for a limited period*** or limited to certain customer classes or subsets of such classes."[32] However, MRC's proposed tariff program contemplates an extended duration, with the new tariff program "remain[ing] open for new enrollments so long as a capacity shortfall exists" or, if a specific duration is established, customers being eligible to "stay on the tariff for 25 years."[33] MRC's proposal for a tariffed rate structure that is either perpetual or in place for a 25-year period is clearly not in keeping with the "pilot rates introduced for a limited period" concept reflected in the Amended Scoping Memo.

Moreover, the Amended Scoping Memo makes clear that where proposals are within the scope of other active Commission proceedings such as the Microgrid proceeding, "the record

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[28] *Prepared Direct Testimony of Allie Detrio on behalf of the Microgrid Resources Coalition*, dated September 1, 2021 (Phase 2 Opening Testimony of MRC), p. 4.

[29] Phase 2 Opening Testimony of MRC, p. 13.

[30] Rulemaking (R.) 19-09-009.

[31] R.21-06-017 rulemaking established three tracks regarding various issues for integration of distributed energy resources into the electric grid.

[32] Amended Scoping Memo, p. 5 (emphasis added).

[33] Phase 2 Opening Testimony of MRC, pp. 17-18.

will be developed in the existing proceeding record and not in this proceeding," and explicitly directs that parties wishing to influence outcomes in the listed proceedings (including the Microgrid proceeding) "shall participate in those proceedings."[34] Here, it makes sense to consider MRC's proposal in the Microgrid proceeding given the complex nature of the proposal and the safety and reliability implications related to proposed modification of Rule 21. While there may be merit to some elements of MRC's proposal – *e.g.*, applicants committing to provide a minimum of 200 kW of as-available capacity to the IOU for a minimum specified period,[35] prohibiting grid charging during capacity shortfall conditions,[36] and minimum performance standards[37] – there are two significant issues that require further evaluation and careful review to support a Commission decision approving MRC's proposal, briefly summarized below:

- *Adjustments to existing rules or tariffs*. The current Rule 21 requirements have been regularly and comprehensively reviewed and refined over time to ensure a reasonable balance of safety and reliability with expediency. Given that the resources proposed by MRC would be exporting to the grid, any amendments to Rule 21 must be subject to careful review to ensure that safety and reliability of the grid can be maintained under the proposal, *especially* under emergency events such as capacity shortfalls where without proper review and system protection installed, a misoperation could result in a larger grid catastrophe exacerbating the emergency event.

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[34] Amended Scoping Memo, p. 5.

[35] Phase 2 Opening Testimony of MRC, p. 5.

[36] *Id*. at p. 7.

[37] *Id*. at pp. 7-8.

- *Compensation structure*. MRC's proposed compensation structure is overly complicated and appears to offer compensation that greatly exceeds the fair value provided by the resources since it includes not only compensation at the retail generation rate,[38] but also exemptions from existing charges such as standby and departing load charges,[39] exemption from interconnection upgrade costs under Rule 2,[40] and additional compensation during emergency events at *twice* the CAISO market cap.[41]

As a practical matter, it is not feasible to develop a complete record on these issues before issuance of a Commission decision in November. Thus, given the fact that MRC's proposal is plainly outside the scope of the instant proceeding and that the compressed procedural schedule adopted in this proceeding would make it impossible to develop a record adequate to support a Commission decision on MRC's proposal, the Commission should not consider MRC's proposal in this proceeding. MRC should, instead, present its ECST compensation tariff proposal in a separate proceeding such as the Microgrid proceeding[42] or the High DER proceeding,[43] where a record can be developed and the proposal can be evaluated more thoroughly by all stakeholders.

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[38] *Id*. at p. 6.

[39] *Id*.

[40] Phase 2 Opening Testimony of MRC, p. 7.

[41] *Id*. at p. 10.

[42] The Commission recently directed parties to submit tariff proposals in Phase 2 of the Microgrid proceeding. *Assigned Commissioner's Amended Scoping Memo and Ruling Setting Track 4: Expedited Phase 1, and Phase 2*, issued in R.19-09-009 on August 17, 2021.

[43] R.21-06-017 includes three tracks addressing various issues related to integration of distributed energy resources into the electric grid.

VI. CONCLUSION

This concludes SDG&E’s prepared reply testimony.

ATTACHMENT A

Lumen Energy Storage Workshop Presentation

Lumen
ENERGY STRATEGY

Energy Storage Procurement Study

STAKEHOLDER WORKSHOP #1: EVALUATION METHODOLOGY AND METRICS

Prepared for:

California Public Utilities Commission and Stakeholders

May 26, 2021

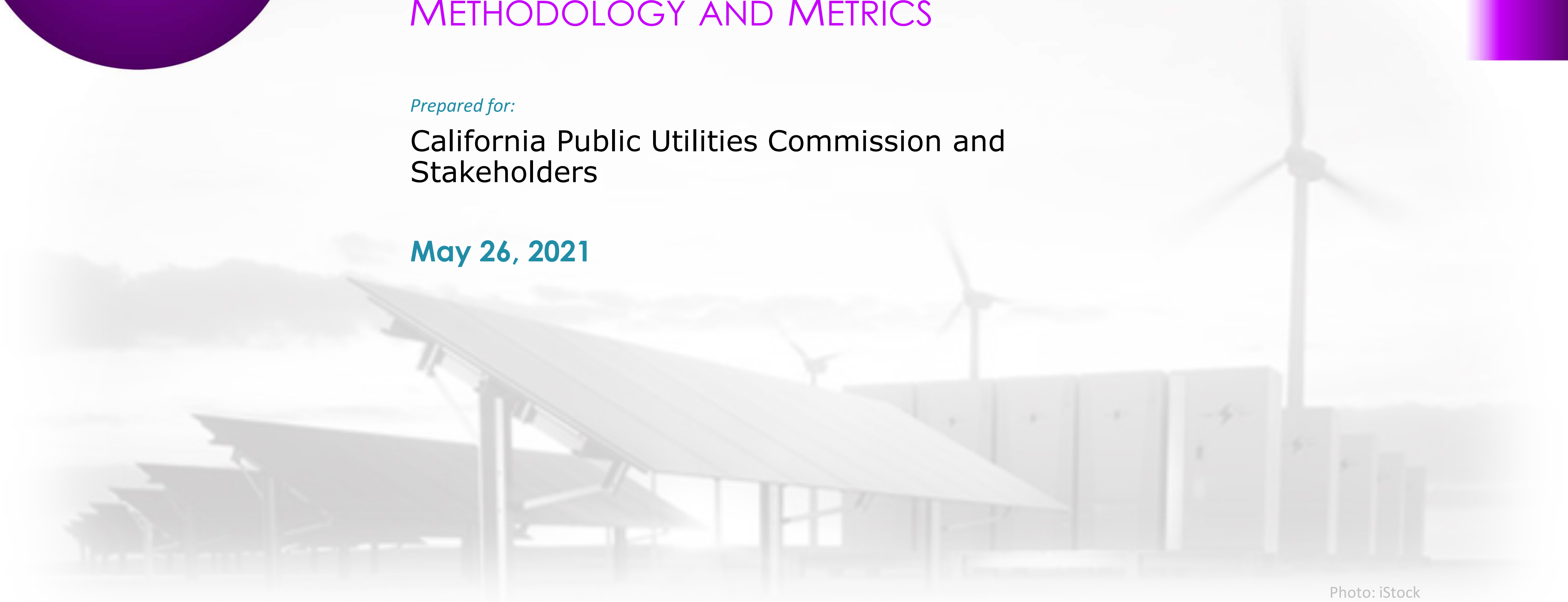


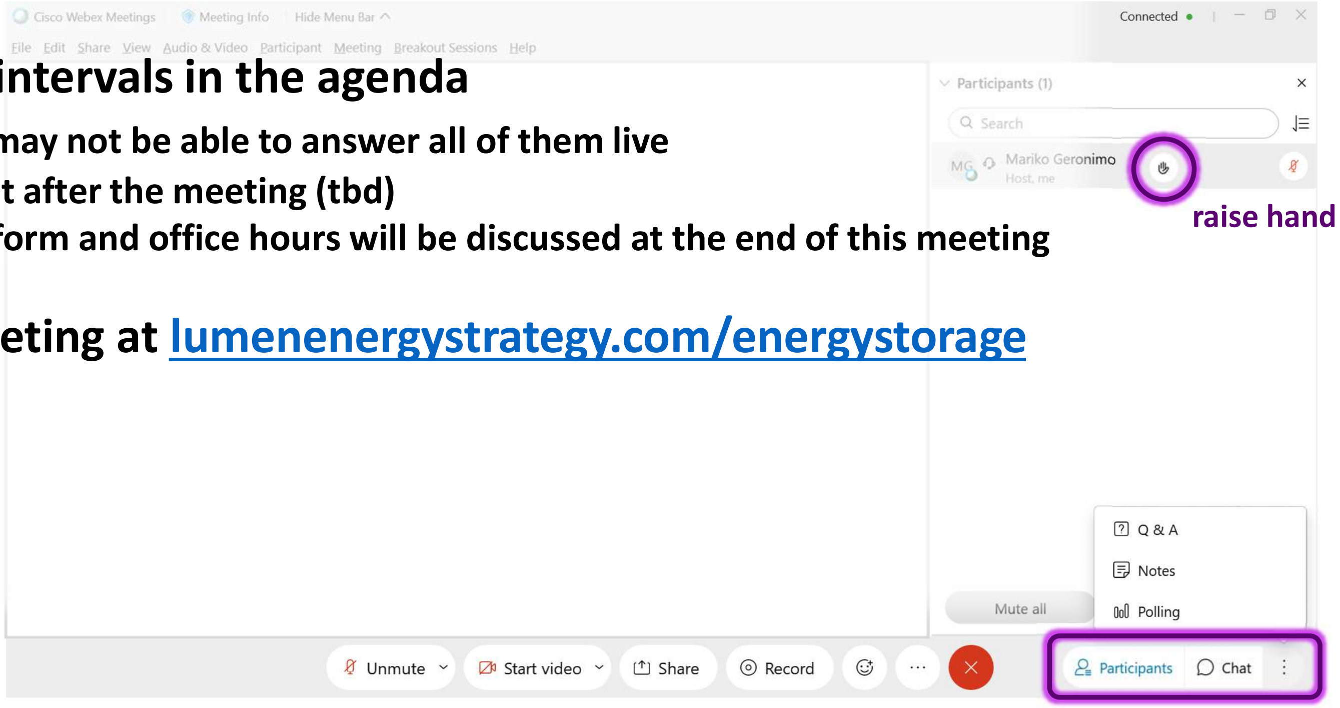
Photo: iStock

Workshop Agenda

APPROX. TIME (PDT)	MINUTES	TOPIC	Q&A
10:00–10:15 a.m.	15	Introductions	Polls
10:15–10:20 a.m.	5	Purpose of Study	
10:20–10:35 a.m.	15	Procedural Background	
10:35–11:00 a.m.	25	Where We Are in Storage Procurement	5 min
11:00–11:05 a.m.	5	—BREAK—	
11:05–11:15 a.m.	10	Study Framework	5 min
11:15–11:45 a.m.	30	Evaluation Methodologies	10 min
11:45 a.m.–12:15 p.m.	30	—BREAK—	
12:15–1:15 p.m.	60	Evaluation Metrics	15 min
1:15–1:20 p.m.	5	—BREAK—	
1:20–1:50 p.m.	30	Cost-Effectiveness and Scoring	15 min
1:50–2:00 p.m.	10	Closing Remarks	

Meeting Logistics

Audio	**All participants are muted; please "raise hand" ✋ to be unmuted during Q&A**
Video	**Sharing your video is optional, but we highly recommend video off to avoid bandwidth issues**
Chat	**We encourage you to chat during presentations to share ideas** **—Please keep your comments friendly and respectful**
Q&A	**We will open Q&A at designated intervals in the agenda** **—Depending on volume of questions, we may not be able to answer all of them live** **—We may follow-up with a Q&A document after the meeting (tbd)** **—We would like your feedback: feedback form and office hours will be discussed at the end of this meeting**
Presentation	**Slides will be posted after the meeting at lumenenergystrategy.com/energystorage**



raise hand

Audience Polls

Purpose of Study

CPUC Decision 13-10-040 requires the CPUC Energy Division to conduct a comprehensive program evaluation of the CPUC Energy Storage Framework and energy storage procurement in compliance with Assembly Bill (AB) 2514 (Skinner, 2010)

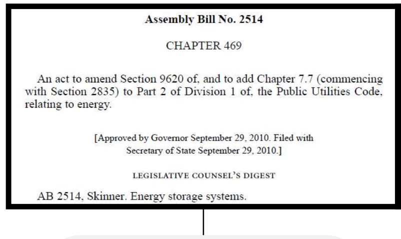
Determine whether the CPUC Energy Storage Procurement Framework and design program and all other energy storage procurement meets the stated purposes of optimizing the grid, integrating renewables, and/or reducing greenhouse gas (GHG) emissions

- Determine progress towards energy storage market transformation
- Learn from actual storage operations and cost data
- Determine best practices for safe operations
- Also investigate other procurement policies in practice, realized value stacking, how to get the most ratepayer value from currently deployed and future procurement, peaker replacements, and recycling and end-of-life options

Why Now?

- California—through AB 2514 and other energy storage procurement directives and initiatives—is a pioneer in energy storage development.
- Ten years ago, energy storage was mostly an **emerging technology**, with many unknowns in terms of costs, operating capabilities, ability to participate in wholesale markets, and long-term cost-effectiveness. At the time, the technology was too new for investors and developers to clearly see a business use case and value proposition for energy storage.
- The CPUC identified this technology as potentially game-changing for providing crucial services to the grid and to customers as the state moves towards an **increasingly clean and sustainable energy future**.
- The CPUC carved a path forward by creating demand for energy storage development, and, in the process, the CPUC has been working to break down barriers to the energy storage market.
- As a result of these directives and initiatives, California has about 1,200 MW of operational energy storage, with much more in development and another 10,000 MW cost-effective energy storage identified in the IRP.
- With the energy storage market accelerating rapidly, now is a critical time to study the performance of the energy storage on the system and discover the technology’s ability, in practice, to meet the state’s objectives of grid optimization, renewable integration, and GHG emissions reductions.

Timeline of Key Mandates and Procurements



Assembly Bill No. 2514

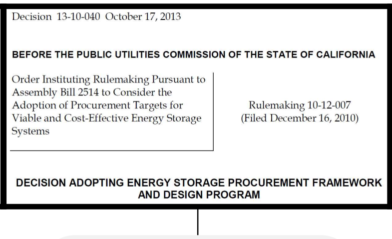
CHAPTER 469

An act to amend Section 9620 of, and to add Chapter 7.7 (commencing with Section 2835) to Part 2 of Division 1 of, the Public Utilities Code, relating to energy.

[Approved by Governor September 29, 2010. Filed with Secretary of State September 29, 2010.]

LEGISLATIVE COUNSEL'S DIGEST

AB 2514, Skinner. Energy storage systems.

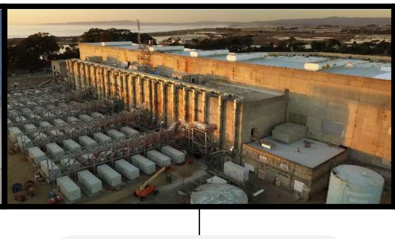


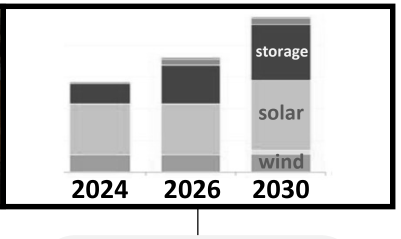
Decision 13-10-040 October 17, 2013

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking Pursuant to Assembly Bill 2514 to Consider the Adoption of Procurement Targets for Viable and Cost-Effective Energy Storage Systems	Rulemaking 10-12-007 (Filed December 16, 2010)

DECISION ADOPTING ENERGY STORAGE PROCUREMENT FRAMEWORK AND DESIGN PROGRAM





2010

AB 2514

Requires consideration of energy storage procurement targets

Purpose of energy storage includes: grid optimization, renewable integration & GHG reductions

2013

D.13-10-040

Establishes 1,325 MW target and biennial procurement cycles

Adopts procurement framework and design program

Allows different evaluation protocols for bid selection

2014

Initial Use Cases

First cycle IOU energy storage procurement plans

Local capacity procurements underway (OTC, SONGS retirements)

Pilots and incentive programs underway

2016–17

AB 2868 (2016)

Additional 500 MW energy storage

Also:
SB 801 & fast-track Aliso Canyon-related procurements underway

Working group (CSFWG) develops DER evaluation framework

2018–19

More Use Cases

Local capacity procurements (Aliso Canyon #2, Moss Landing)

First distribution investment deferral framework (DIDF) procurements

3,300 MW of system reliability procurements initiated

2020–21

System Reliability

System reliability "fast track" procurements (online by August 1 of 2021)

2019/20 IRP Reference System Portfolio: 10 GW energy storage by 2030

From left to right: California Assembly Bill No. 2514 (2010, Skinner); CPUC Decision 13-10-040, October 17, 2013, under Rulemaking 10-12-007; Customer-sited Irvine Co./AMS Hybrid-Electric Building Technologies contracted under SCE's 2013 LCR RFO for the Western LA Basin (image credit: Irvine Company); Distribution-sited Tesla Mira Loma project under SCE's 2016 Aliso Canyon RFO (image credit: Patrick T. Fallon/Bloomberg); Transmission-sited Vistra Moss Landing project contracted under PG&E's 2018 Moss Landing RFO (image credit: InsideEVs.com); Incremental new resources in CPUC-adopted 2019-2020 Reference System Portfolio (CPUC Decision 20-03-028).

Study Timeline

CPUC issued a Request for Information (RFI) to determine desired study scope, timeline and contractor requirements (Mar 2020)

CPUC incorporated RFI responses and released a competitive solicitation to select a contractor to support CPUC for the energy storage study (Aug 2020)

Notice of Intent to Award (Dec 2020)

Contract award & study kickoff (Mar 2021)

STAKEHOLDER WORKSHOP 1
(May 2021)
- Study purpose and objectives
- Framework for project evaluation

STAKEHOLDER WORKSHOP 2
(Q3 2021)
- Final evaluation framework
- Initial observations on project use cases and operations

STAKEHOLDER WORKSHOP 3
(Q1 2022)
- Preliminary findings on project evaluations
- Notable successes and challenges

DRAFT STUDY REPORT & STAKEHOLDER WORKSHOP 4
(Q2 2022)
- Final project evaluations and scoring
- Draft study recommendations

FINAL STUDY REPORT (Q3 2022)

2020 | **2021** | **2022**

Energy Storage Procurement in California

“Energy Storage” in this Study

- **In this study, we will consider the following energy storage projects:**
  - Mechanical, chemical, or thermal*
  - Procured by CPUC-jurisdictional load-serving entities to meet specific mandates (such as AB 2514, IRP)
  - All existing or new resources within the geography of California’s investor-owned utility service territories—to assess the state’s energy storage market evolution

*See CPUC Decision 16-01-032 for discussion and clarifications on energy storage technologies eligible to meet AB 2514 mandates.

California’s electric investor-owned utility (IOU) service territories. Image credit: California Energy Commission.

Clockwise from top left: Olivenhain Reservoir (Lake Hodges pumped storage), image credit: San Diego County Water Authority; Gateway Project, image credit: LS Power/Silverline Productions, Inc./Vimeo (company video); Thermal energy storage (TES) tank at Chaffey College, image credit: HPAC Engineering; Tesla Powerpack system, image credit: Tesla, Inc.

A Few Key Terms

Energy storage grid domains

- Energy storage can be sited and installed at the bulk grid level in front of the CAISO meter (transmission domain), on the distribution system in front of the customer meter (distribution domain) or behind the customer meter (customer domain)

Use cases

- A technical, operational, and economic model for providing a specific set of services (e.g., resource adequacy vs. distribution deferral vs. microgrid)

Energy storage mandate "counterfactual"

- Without the energy storage mandate and procurements, how would your resource portfolio and operations change?

Benefits & value streams of energy storage

- Costs avoided by energy storage procurement and operations ("avoided costs"), relative to counterfactual

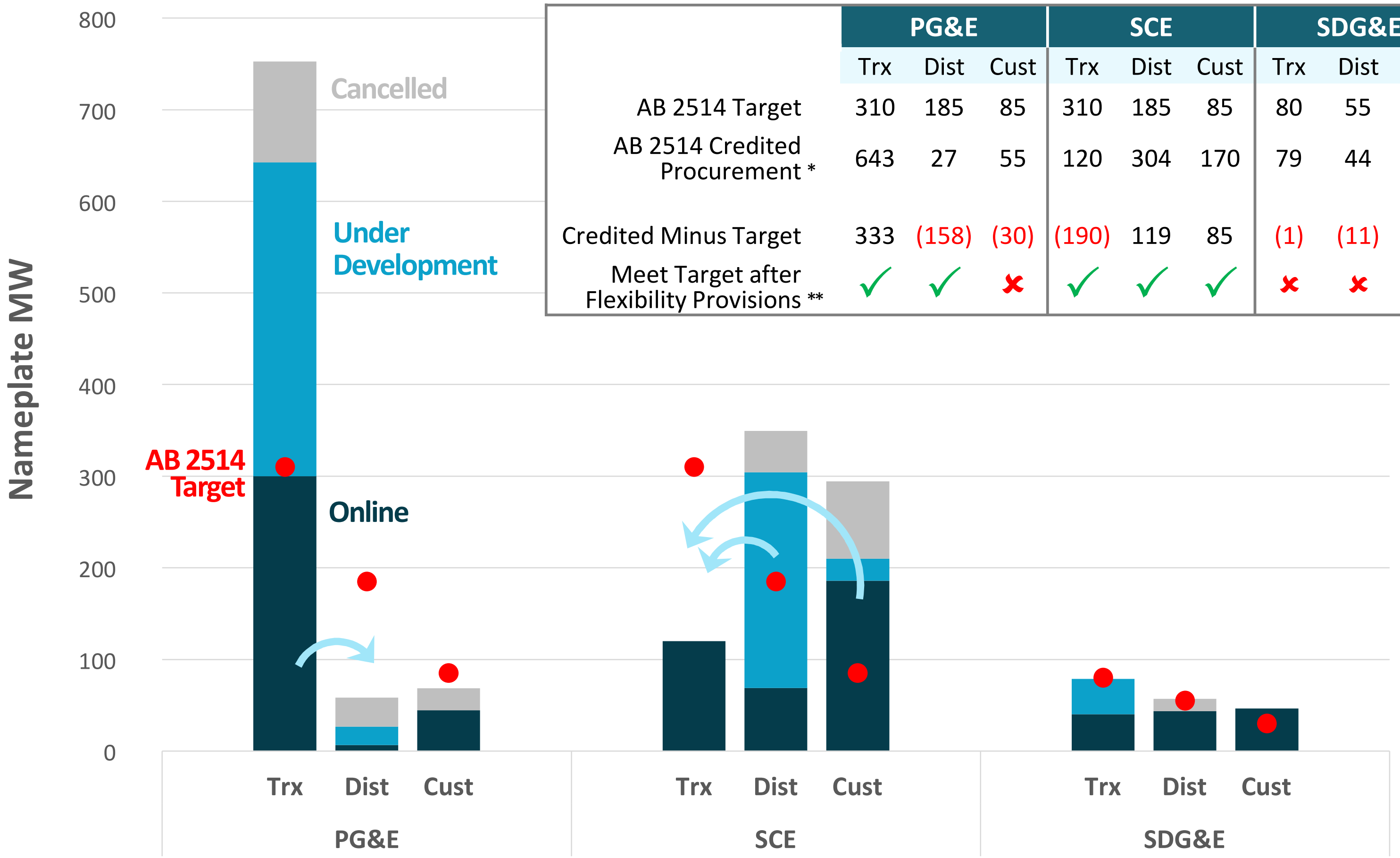
Self-Generation Incentive Program (SGIP)

- Provides rebates for qualifying distributed energy resources installed on customer side of the utility meter, including energy storage systems. SGIP accounts for a large share of operating energy storage in California.

Procurement track

- Due to the cross-cutting nature of energy storage, the investor-owned utilities and other load-serving entities procure CPUC-approved energy storage through a wide range of proceedings, including:
  - SGIP and other pilots & programs
  - Distributed resource planning
  - Distribution investment deferral
  - Local (LCR) and system (IRP) capacity

Energy Storage for AB 2514 Compliance



	PG&E			SCE			SDG&E		
	Trx	Dist	Cust	Trx	Dist	Cust	Trx	Dist	Cust
AB 2514 Target	310	185	85	310	185	85	80	55	30
AB 2514 Credited Procurement *	643	27	55	120	304	170	79	44	47
Credited Minus Target	333	(158)	(30)	(190)	119	85	(1)	(11)	17
Meet Target after Flexibility Provisions **	✓	✓	✗	✓	✓	✓	✗	✗	✓

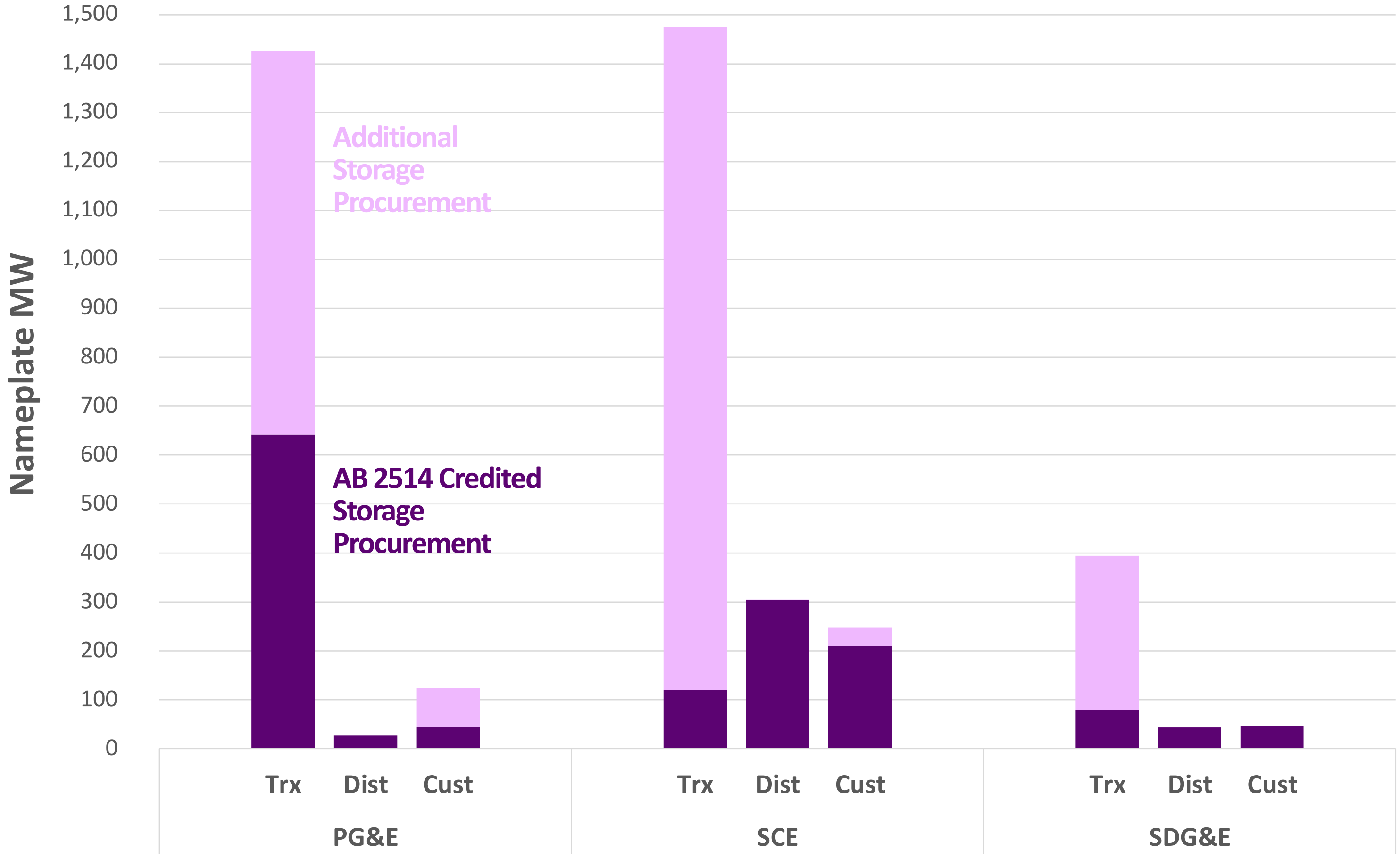
Source: Lumen research based on utility AB 2514 compliance filings, advice letters on SGIP credits, web research, and IOU-provided clarifications on project size and development status. Trx = transmission-sited; Dist = distribution-sited; Cust = customer-sited.

* Excludes retired and cancelled projects.

** CPUC's flexibility provisions allow limited substitution between domains to meet targets. IOUs can shift up to 80% of MWs between the transmission and distribution domains (CPUC Decision 13-10-040). IOUs can also satisfy some of their T&D domain targets through non-SGIP customer-connected projects, subject to a procurement ceiling of 200% of customer domain targets (CPUC Decision 16-01-032).

- Projects approved for AB 2514 compliance are on track to meeting 1,325 MW mandate
  - PG&E's 30 MW shortfall in customer targets will likely be met by additional Self Generation Incentive Program (SGIP)-funded projects
  - SDG&E's plan to meet 12 MW shortfall in transmission and distribution targets in progress
- Targets for T&D domains are met with the flexibility provisions
- Cancellations and delays occur, so it is important to keep track of projects under development to make sure they're online by the 2024 deadline

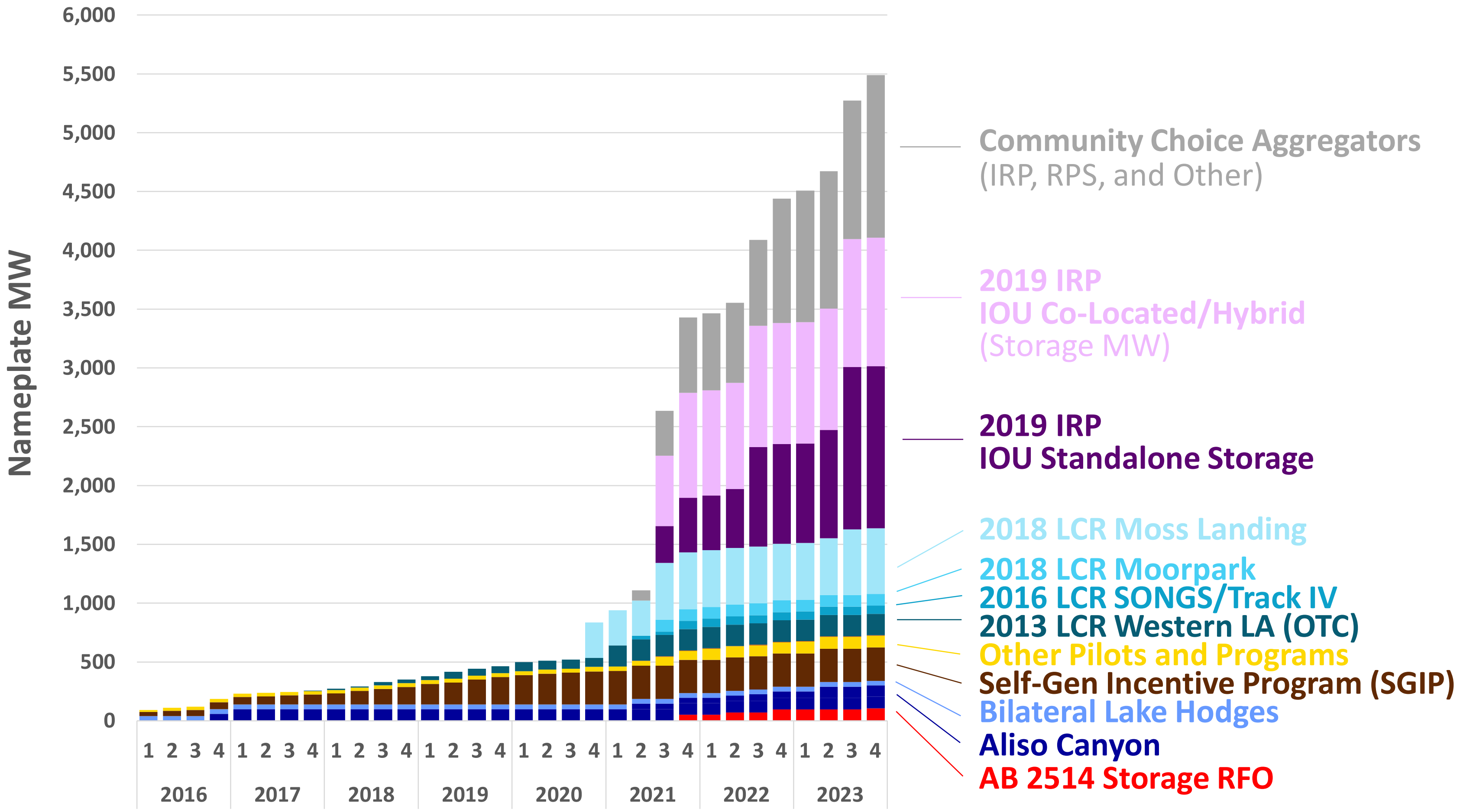
IOU Procurement beyond AB 2514



Source: Lumen research based on utility applications and CPUC decisions on various resource procurement tracks, and other public information on project status. Trx = transmission-sited; Dist = distribution-sited; Cust = customer-sited.

- Overall energy storage procurement significantly exceeds the AB 2514 target of 1,325 MW
- Additional energy storage capacity is procured mainly for the IRP track initiated in 2019
  - Integrated Resource Plan and Long Term Procurement Plan (IRP-LTPP)
  - CPUC Decision 19-11-016 ordered 3,300 MW of incremental capacity online by 2021–2023 for near-term reliability
  - Most of this need will be met by standalone storage and solar+storage

Energy Storage by Procurement Track

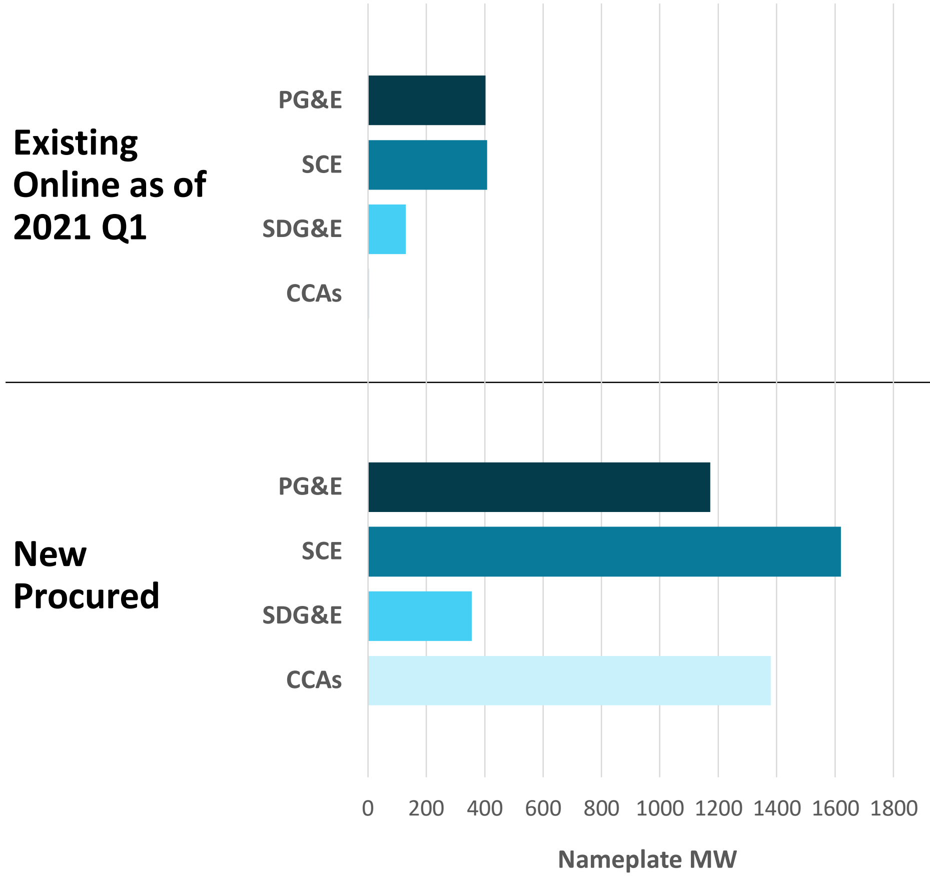


Source: Lumen research based on utility applications and CPUC decisions on various resource procurement tracks, and other public information on project status. (IRP = Integrated Resource Plan; RPS = Renewable Portfolio Standard; LCR = Local Capacity Requirement; OTC = Once-Through Cooling (retirements); RFO = Request for Offers.)

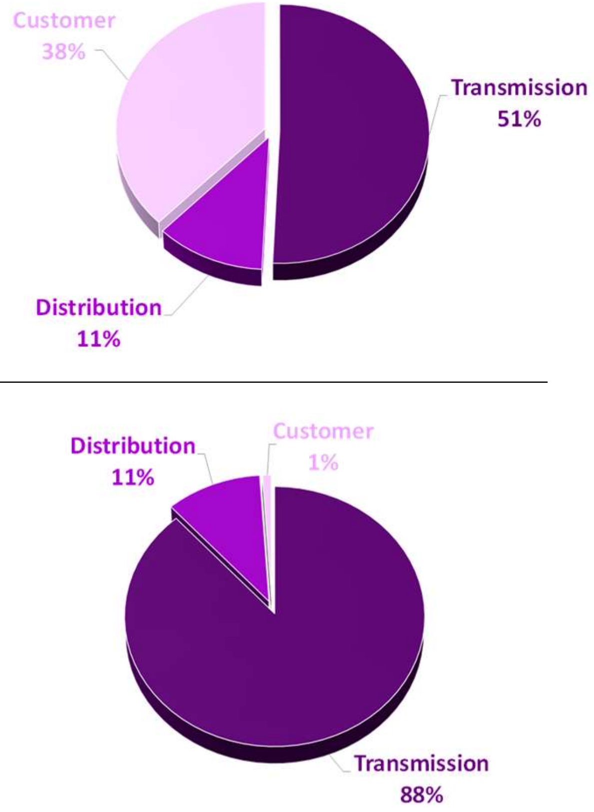
- Significant growth in energy storage capacity driven by various procurement tracks
- Current capacity surpassed 1,000 MW, which is >2x relative to last year
- With the upcoming projects, there will be over 3,000 MW online by the end of this year; more than 5,500 MW in 2023

Energy Storage by LSE and Grid Domain

By Load-Serving Entity (LSE)



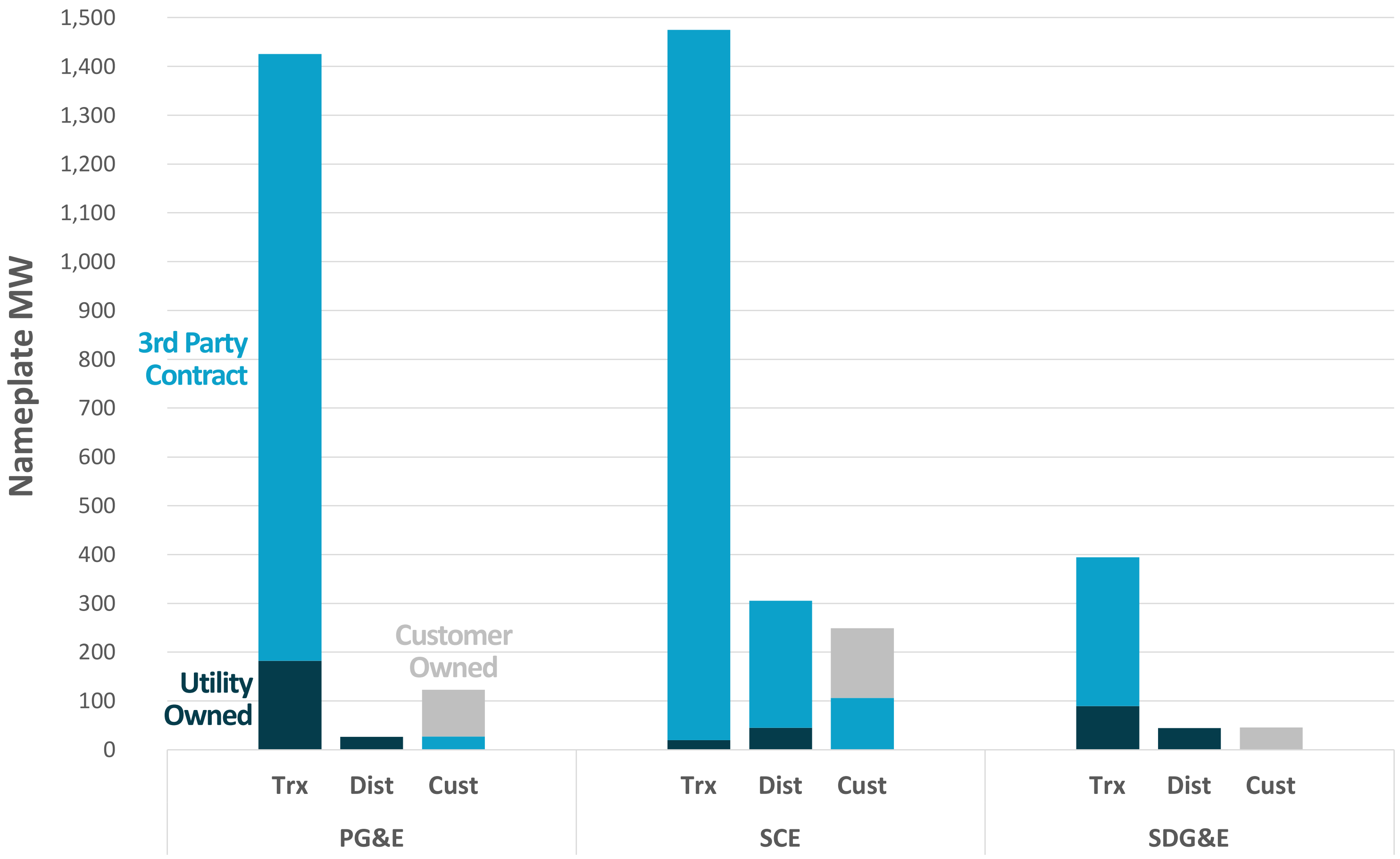
By Grid Domain



Source: Lumen research based on utility applications and CPUC decisions on various resource procurement tracks, and other public information on project status.

- Current storage mix of facilities at the transmission, distribution, and customer domains
- Most near-term projects procured at the transmission domain
- Customer-sited projects will likely continue to grow due to Self-Generation Incentive Program (SGIP)
  - SGIP future growth not shown in the charts here

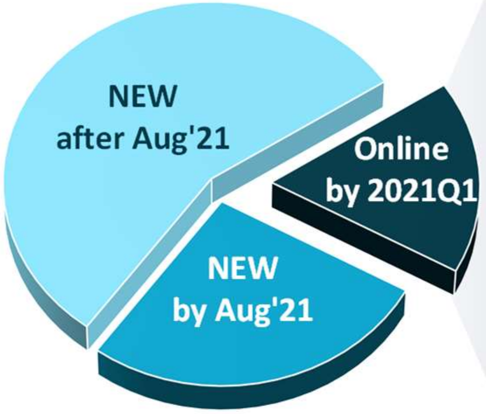
Energy Storage by Ownership



Source: Lumen research based on utility applications and CPUC decisions on various resource procurement tracks, and other public information on project status. Trx = transmission-sited; Dist = distribution-sited; Cust = customer-sited.

- More than 80% of storage capacity procured under 3rd-party contracts
  - Most contracts for "RA only": utility buys resource adequacy (RA) capacity and counterparty retains all other attributes including energy and ancillary services
- Utility-owned projects account for 10% of storage procurement (~400 MW); most already online or expected to be online later this year

Operational Energy Storage Projects



Project Name	LSE	Grid Domain	Storage Capacity MW
Vistra Moss Landing	PG&E	Transmission	300
Gateway*	Various	Transmission	250
AES Alamitos ES	SCE	Transmission	100
Vista*	SDG&E	Transmission	40
Lake Hodges Pumped Hydro	SDG&E	Transmission	40
Escondido	SDG&E	Distribution	30
HEBT WLA1 DRES	SCE	Customer	25
AltaGas Pomona Energy	SCE	Distribution	20
Tesla Mira Loma	SCE	Distribution	20
Stem Energy DRES - 402040	SCE	Customer	20
HEBT WLA2 DRES	SCE	Customer	15
Orni 34/Vallecito	SCE	Distribution	10
SCE EGT - Center	SCE	Transmission	10
SCE EGT - Grapeland	SCE	Transmission	10
Tehachapi	SCE	Distribution	8
El Cajon	SDG&E	Distribution	7.5
HEBT Irvine1 DRES	SCE	Customer	5
HEBT Irvine2 DRES	SCE	Customer	5
Subtotal			**916**
SGIP PBI		Customer	163
SGIP Non-PBI residential		Customer	82
SGIP Non-PBI other		Customer	38
Other Distribution		Distribution	23
Other Customer		Customer	18
TOTAL			**1,240**

15,000+ projects

* Gateway and Vista projects are developed in phases, starting w/ 1-hr duration and building more capacity over time to meet RA obligations under IRP-related contracts. While not counting towards AB 2514 targets, they are among the few large energy storage projects that are in service. Thus, we will include an analysis of their operations and market participation to gain additional insights on performance of utility-scale projects.

- Our study will focus on energy storage projects with actual operational data
- Total installed capacity ~1.2 GW as of 2021 Q1
- About half of this capacity from projects installed recently (e.g., Vistra Moss Landing, AES Alamitos) with less than 6-months of operations

Q&A

- —Purpose of study
- —Procedural background
- —Study timeline
- —Where we are in energy storage procurement

5-MINUTE BREAK

WILL RETURN AT 11:05 A.M. PDT

NEXT UP: STUDY FRAMEWORK AND EVALUATION METHODOLOGIES

Study Framework

Overall Study Framework

Data

- Project characteristics
- Actual operations
- Deferred investments
- CAISO market settlements
- BTM storage customer characteristics
- Project financials & contract data
- Industry reports &studies

including cluster analysis & sampling

Analyses

Impacts
(2017–2021)

- Bulk grid services
- Capital investments
- Local/site services
- GHG emissions

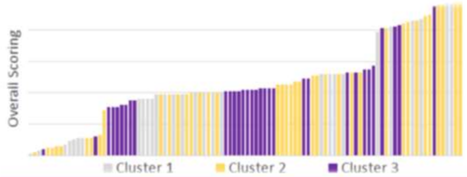
Benefits $
(2017–2021)

Costs $
(2017–2021)

Score & Rank

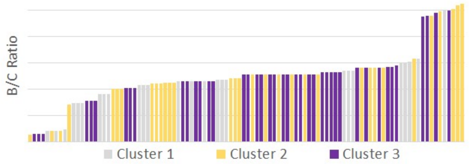
Effectiveness at meeting AB 2514 Goals

- Avoided renewable curtailments
- Production & investment cost savings
- System/local/site services provided
- GHG emissions reductions



Cost-effectiveness (2017–2021)

Ratepayer, total resource cost, societal



Policy & Market Drivers

- Profiles of **most effective** storage in operation
- Identify **barriers** faced by least effective storage projects
- Industry & storage development market **lessons learned**
- Special studies including **economic potential**

Policy Pathways

Today’s Focus

Data

- Project characteristics
- Actual operations
- Deferred investments
- CAISO market settlements
- BTM storage customer characteristics
- Project financials & contract data
- Industry reports &studies

including cluster analysis & sampling

Analyses

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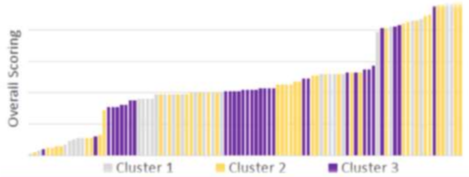

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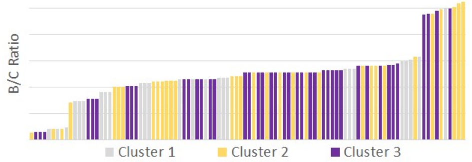

Policy & Market Drivers

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- Identify **barriers** faced by least effective storage projects
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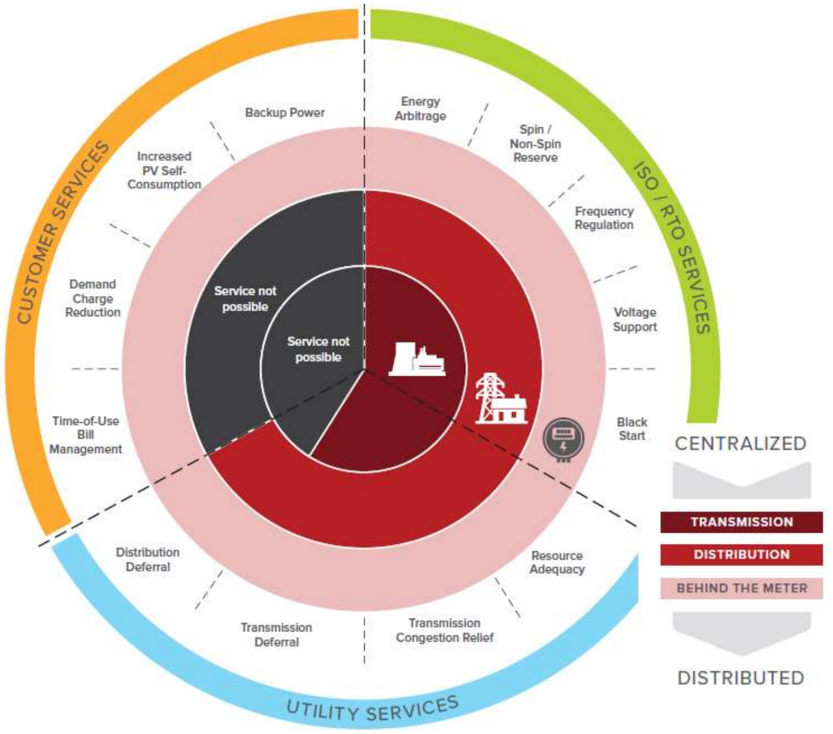
Policy Pathways

Q&A

—OVERALL STUDY FRAMEWORK

Evaluation Methodologies

Potential Value to Grid and Customers



Source: Fitzgerald, Garrett, et al., Rocky Mountain Institute (RMI), "The Economics of Battery Energy Storage," October, 2015.

		Services that can be provided based on **Grid Domains**		
	Services to Grid and Customers	**Transmission**	**Distribution**	**Customer**
Energy & AS Markets and Products	Energy	✓	✓	✓
	Frequency Regulation	✓	✓	✓
	Spin/Non-Spin Reserve	✓	✓	✓
	Flexible Ramping	✓	✓	✓
	Voltage Support	✓	✓	✓
	Black Start	✓	✓	✓
Resource Adequacy	System RA Capacity	✓	✓	✓
	Local RA Capacity	✓	✓	✓
	Flexible RA Capacity	✓	✓	✓
T & D Related	Transmission Investment Deferral	✓	✓	✓
	Distribution Investment Deferral		✓	✓
	Microgrid/Islanding		✓	✓
Site-Specific & Local Services	TOU Bill Management			✓
	Demand Charge Management			✓
	Increased Use of Self-Generation			✓
	Backup Power			✓

Survey of Evaluation Methodologies

Consistent Evaluation Protocol (2014)

See CPUC Decision 14-10-045

Guideline for benchmarking and general reporting purposes; not used for bid selection

Relies on standardized and publicly available inputs, primarily those in CPUC Avoided Cost Calculator (ACC)

Net Market Value (NMV) + descriptive information + flag for primary/secondary end uses

Competitive Solicitation Framework (2016)

See CPUC Decision 16-12-036

Guideline for competitive solicitations for distributed energy resources (DERs)

Technology-neutral and applicable to all DERs

Least-cost best-fit approach

Also the basis for selecting DERs under Distribution Investment Deferral Framework (DIDF)

IOU Least-Cost Best-Fit / Adjusted Net Market Value

Described in each IOU procurement application or advice letter

Tailored to each IOU and objectives of each solicitation

Used for bid evaluation, shortlisting, and bid selection

Overall value assessment relies on:
- Value implied in RFO preferences and bid constraints
- NMV calculation using proprietary models and future market price curves
- Adjustments to NMV via weightings and multipliers
- Qualitative factors that increase or decrease a bid’s relative rank

SGIP Storage Evaluation Studies

Annual retrospective analysis of actual impacts, following CPUC M&E plan
- Energy storage performance metrics, utility marginal cost impacts, customer impacts, and environmental impacts
- Also studies impacts of hypothetical optimal dispatch under various scenarios

Going-forward storage market assessment and cost-effectiveness report (2019)
- Applies all CPUC-adopted cost-effectiveness tests per CPUC Decision 19-05-019

- CPUC, IOUs, and stakeholders have put forth significant effort to **identify, quantify, and monetize** the multiple value streams of energy storage
- Efforts yielded ground-breaking approaches to monetize non-traditional value streams
  - E.g., distribution deferral value
- Challenges to incorporate identified benefits that are difficult to quantify or monetize
  - Combine monetization with expert judgment: least-cost best-fit (LCBF) and adjusted net market value (adj. NMV)
  - Some benefits recognized via project and contract preferences in IOU solicitations

Benefits Monetized and Considered

■ Monetized
▨ Considered but not monetized

	Services and Benefits	Consistent Evaluation Protocol (CEP) Forward Looking	Competitive Solicitation Framework (by CSFWG) Forward Looking	IOU Least-Cost Best-Fit (LCBF) Forward Looking	SGIP Energy Storage Evaluation Studies Forward-Looking & Retrospective	CPUC/Lumen STUDY Retrospective
Energy & AS Markets and Products	Energy	■	■	■	■	■
	Ancillary Services	■	■	■	■	■
	Flexible Ramping	▨				■
	Voltage Support/Power Quality	▨	▨	▨		■
	Black Start	▨				■
Resource Adequacy	System RA Capacity	■	■	■	■	■
	Local RA Capacity		■	■		■
	Flexible RA Capacity		■	■		■
T&D Related	Transmission Investment Deferral	▨	■	▨		■
	Distribution Investment Deferral	■	■	■	■	■
	Microgrid/Islanding	▨		▨		■
Site-Specific & Local Services	TOU Rate and Demand Charge Management	▨			■	▨
	Increased Use of Self-Generation				▨	▨
	Backup Power	▨			■	■

Least-Cost Best-Fit Evaluation Approach

In this study, we will follow an approach that considers both monetized and non-monetized evaluation metrics

	Evaluation scope	Evaluation metrics
Monetized	Cost-effectiveness	Benefit-cost ratios
Quantified	Effectiveness at meeting AB 2514 goals	Scorecards

- Metrics calculated at the project level
- We will apply a single framework across all types of projects
- Most benefits we have listed will be monetized; all will be quantified
- Clear separation of market analysis from ranking of difficult-to-monetize benefits
  - Cost-effectiveness tests will reflect monetized benefits and costs, unadjusted for statutory and solicitation-specific preferences
  - Effectiveness at meeting AB 2514 goals will be quantified via a simple scoring and weighting
- Goals for evaluation metrics to yield apples-to-apples comparisons among projects in the same 2017–2021 time period

Interpretation of Evaluation Metrics

- Our results can yield insights to how operating projects and use cases compare to each other

- Many limitations to comparisons with prospective evaluations and planning study outcomes (see right)

- However, retrospective study will need to draw assumptions from planning studies
  - E.g., Long-run avoided costs of meeting RPS and GHG-related mandates

	This **Retrospective** Evaluation	**VS.**	A **Prospective** Planning Study
Timeframe	2017–2021 actual historical		10–20 years forward
Storage installation	Project-specific		Generic
Operating period	Snapshot (partial life)		Entire project life
Weather conditions	Actual, volatile		Normalized
Electricity consumption	Actual, cyclical		50/50 or 90/10 weather, smoothed economic and population projections
Grid conditions	Actual infrastructure with unexpected outage events and real-time volatility		(some) hypothetical infrastructure with limited/no unexpected outages and muted real-time volatility
Market prices	Actual/volatile; partial view of potentially back-loaded benefits		Smoothed, optimized with a long-run foresight of benefit streams
Energy storage project costs	Partial view of potentially front-loaded costs		Full view, and investment optimized with market price outcomes
Long-run avoided costs	Estimated cost to re-balance investments to meet resource adequacy, renewable portfolio standard, and GHG emissions targets and mandates		

Q&A

—EVALUATION METHODOLOGIES

30-MINUTE BREAK

WILL RETURN AT 12:15 P.M. PDT

NEXT UP: EVALUATION METRICS

Benefit & Performance Metrics

Benefit & Performance Metrics

Data

Project characteristics

Actual operations

Deferred investments

CAISO market settlements

BTM storage customer characteristics

Project financials & contract data

Industry reports &studies

including cluster analysis & sampling

Analyses

Impacts
(2017–2021)

Bulk grid services

Capital investments

Local/site services

GHG emissions

Benefits $
(2017–2021)

Costs $
(2017–2021)

Score & Rank

Effectiveness at meeting AB 2514 Goals

Avoided renewable curtailments

Production & investment cost savings

System/local/site services provided

GHG emissions reductions

Cost-effectiveness (2017–2021)

Ratepayer, total resource cost, societal

Policy & Market Drivers

Profiles of **most effective** storage in operation

Identify **barriers** faced by least effective storage projects

Industry & storage development market **lessons learned**

Special studies including **economic potential**

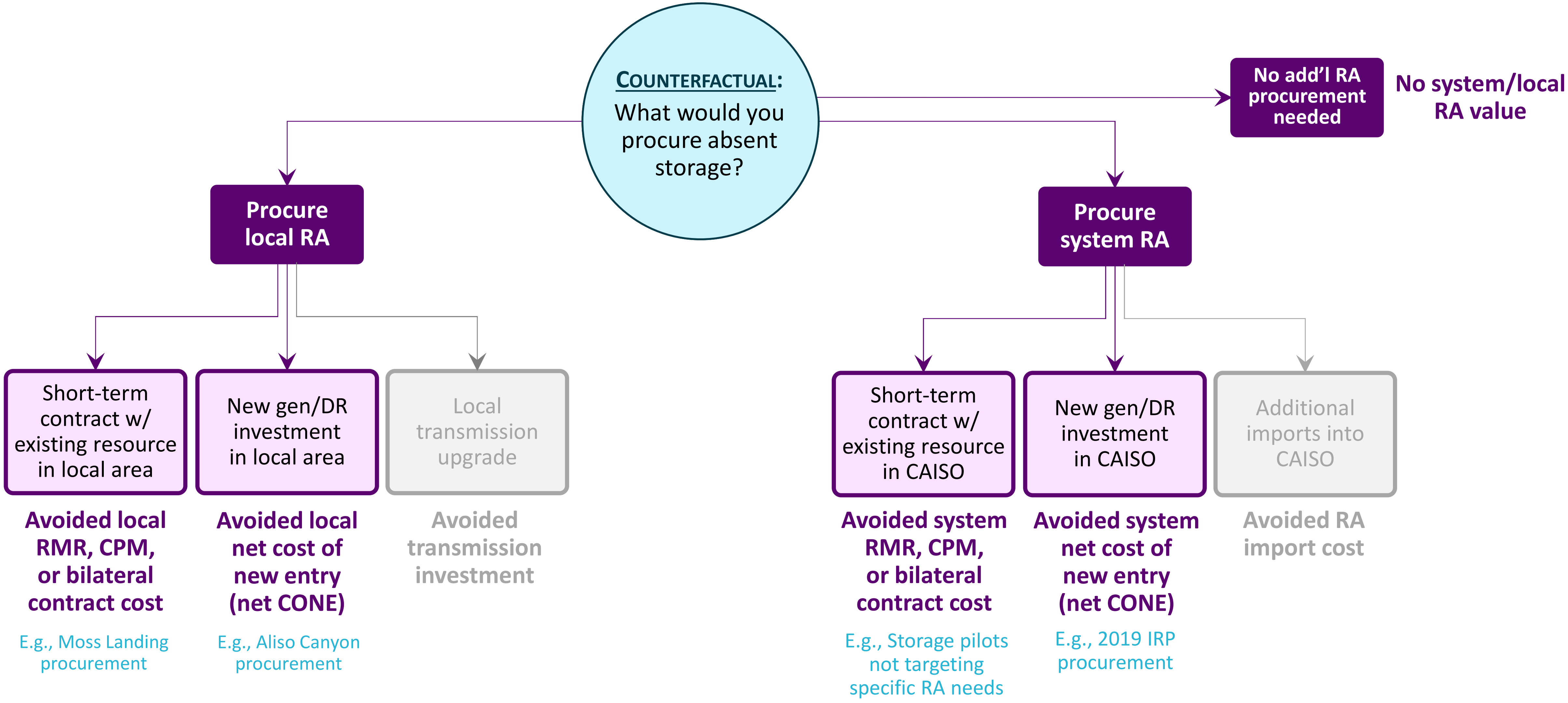
Policy Pathways

Energy & Ancillary Services Market Value

- **Analyze each project’s historical energy charge/discharge patterns**
  - Value day-ahead (DAM) and real-time (RTM) settlements
  - Impact on marginal generation and GHG emissions
  - Impact on renewable curtailments
- **Analyze storage project’s participation in CAISO ancillary services markets**
  - MW cleared and MW called upon for regulation and contingency reserves
- **Review settlements for:**
  - CAISO’s flexible ramping product
  - CAISO contracts for black start and voltage support

	CAISO Market Participants (including demand response)	**Non-Participant Behind CAISO Meter**
Energy	Valued at actual nodal DAM and RTM market prices and settlements	Valued at RTM price
Frequency Regulation		n/a
Spin/Non-Spin Reserve		n/a
Flexible Ramping		n/a
Voltage Support	Based on CAISO contract payments	n/a
Black Start		n/a

Capacity Value: Creating the Counterfactual



COUNTERFACTUAL:
What would you procure absent storage?

No add'l RA procurement needed

No system/local RA value

Procure local RA

Short-term contract w/ existing resource in local area

Avoided local RMR, CPM, or bilateral contract cost

E.g., Moss Landing procurement

New gen/DR investment in local area

Avoided local net cost of new entry (net CONE)

E.g., Aliso Canyon procurement

Local transmission upgrade

Avoided transmission investment

Procure system RA

Short-term contract w/ existing resource in CAISO

Avoided system RMR, CPM, or bilateral contract cost

E.g., Storage pilots not targeting specific RA needs

New gen/DR investment in CAISO

Avoided system net cost of new entry (net CONE)

E.g., 2019 IRP procurement

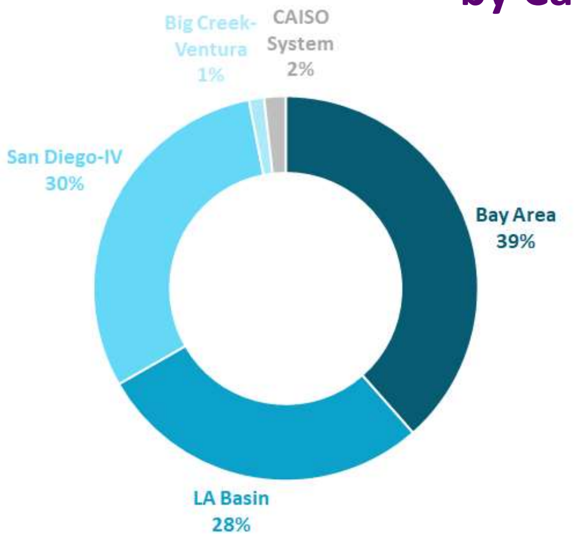
Additional imports into CAISO

Avoided RA import cost

Capacity Value: System & Local Resource Adequacy

- **Review capacity commitments**
  - Document net qualifying capacity (NQC) of projects counting towards system and local RA needs
- **Estimate capacity value from:**
  - New generation or demand response investment deferred
  - Avoided short-term RA contracts to retain existing resources, such as Reliability Must-Run (RMR) contracts
- **Report projects' performance during supply-constrained hours, such as:**
  - Top hours w/ highest net system load
  - System emergency events

Operational Energy Storage MW by Capacity Area



Most online storage capacity was procured to meet local capacity and reliability needs

	Local Capacity Area				CAISO	Total	CPUC	Approx.
	Bay Area	LA Basin	San Diego-IV	Big Creek-Ventura	System	Capacity	Approval	Lead Time
Aliso Canyon (ACES)	0	44	38	0	0	**82**	Aug-16	< 4 mo
Aliso Canyon (ACES 2)	0	0	0	10	0	**10**	Dec-19	~15 mo
LCR-2013 (OTC)	0	176	0	0	0	**176**	Nov-15	3-5 yrs
LCR-2018 (Moss Landing)	300	0	0	0	0	**300**	Nov-18	2 yrs
2019 IRP Near-Term	0	0	160	0	0	**160**	Aug-20	< 1 yr
Bilateral Lake Hodges	0	0	40	0	0	**40**	Aug-04	4+ yrs
Other	4	2	1	0	14	**21**		
TOTAL	**304**	**223**	**239**	**10**	**14**	**790**		

Capacity Value: Behind-the-Meter Resources

- **BTM distributed and customer-sited energy storage projects can provide capacity values by:**
  - Participating in demand response programs that are integrated to the CAISO market on the supply-side
  - Reducing net coincident peak as a load modifying resource under various retail incentive programs and rates
    - Permanent Load Shifting (PLS)
    - Time of Use (TOU)
    - Critical Peak Pricing (CPP)
    - Peak Day Pricing (PDP)
    - Real-Time Pricing (RTP)

Use qualified RA capacity included in LSE plans

Estimate capacity contribution based on actual net discharge during top hours w/ largest net system load

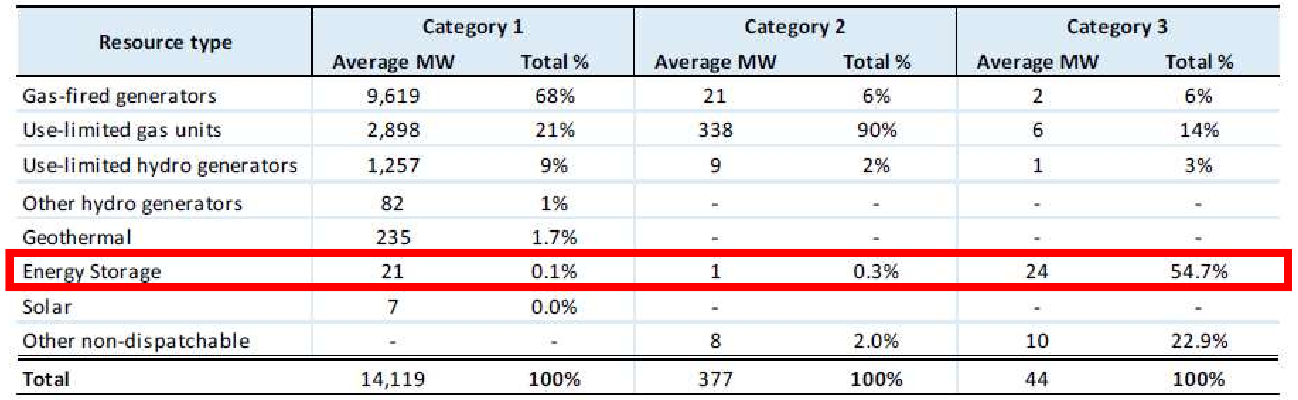
Capacity Value: Flexible RA

- **Review and document effective flexible capacity (EFC) included in LSE plans**
- **Estimate flexible RA value based on incremental cost of flexible capacity procurements**
  - LSE contracts often bundled for system, local, and flexible RA attributes
  - Need to compare cost of resources providing flexible RA vs. not
  - Unlike conventional resources, storage can provide up to 2x of its nameplate capacity for flexible RA

Flexible RA Categories

	1. Base	2. Peak	3. Super-Peak
Basis for Operational Needs	Largest 3-hr secondary net load ramp	95% of max 3-hr primary net load ramp *minus* largest 3-hr secondary net load ramp	5% of max 3-hr primary net load ramp
Must-Offer Obligations	17 hours/day 7 days/week	5 hours/day 7 days/week	5 hours/day Non-holiday weekdays

2019 Flex RA Procurement by Resource Type



Resource type	Category 1		Category 2		Category 3	
	Average MW	Total %	Average MW	Total %	Average MW	Total %
Gas-fired generators	9,619	68%	21	6%	2	6%
Use-limited gas units	2,898	21%	338	90%	6	14%
Use-limited hydro generators	1,257	9%	9	2%	1	3%
Other hydro generators	82	1%	-	-	-	-
Geothermal	235	1.7%	-	-	-	-
Energy Storage	21	0.1%	1	0.3%	24	54.7%
Solar	7	0.0%	-		-	-
Other non-dispatchable	-	-	8	2.0%	10	22.9%
Total	**14,119**	**100%**	**377**	**100%**	**44**	**100%**

Source: CAISO DMM, 2019 Annual Report on Market Issues and Performance.

Q&A

—RESOURCE ADEQUACY

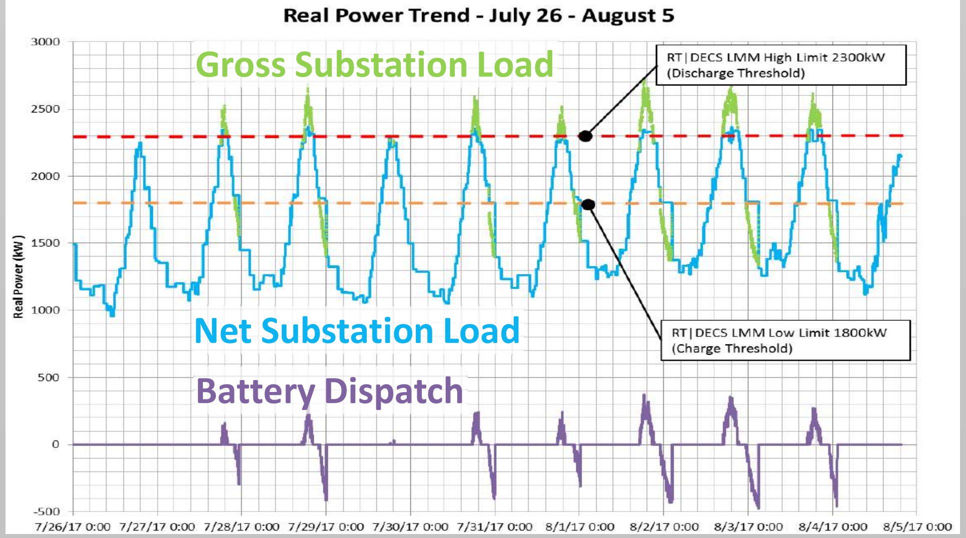
T&D Investment Deferral

- **Review stated distribution upgrades deferred by storage projects**
  - Focus on <u>specified</u> deferral value from targeted procurements (e.g., DIDF proceedings)
  - Applies to only a handful of operating projects
  - Document location and characteristics of deferred upgrades
- **Analyze projects' performance during distribution capacity-constrained hours**
  - Start w/ actual net load of the distribution system where upgrade is deferred
  - Estimate counter-factual load without storage
  - Compare against peak capacity

Example: PG&E's Browns Valley

EPIC Project 1.02 Energy Storage for Distribution Operations

- 0.5 MW/2 MWh system of 22 Tesla Powerpacks, online in 2016
- Up to 4 hours of loading relief on the 2.4 MW Browns Valley substation transformer bank
- Sized to address projected 10 years of substation peak loading
- Project kept peak loading below 2.3 MW during two summer heat wave events in 2017 (see figure below)

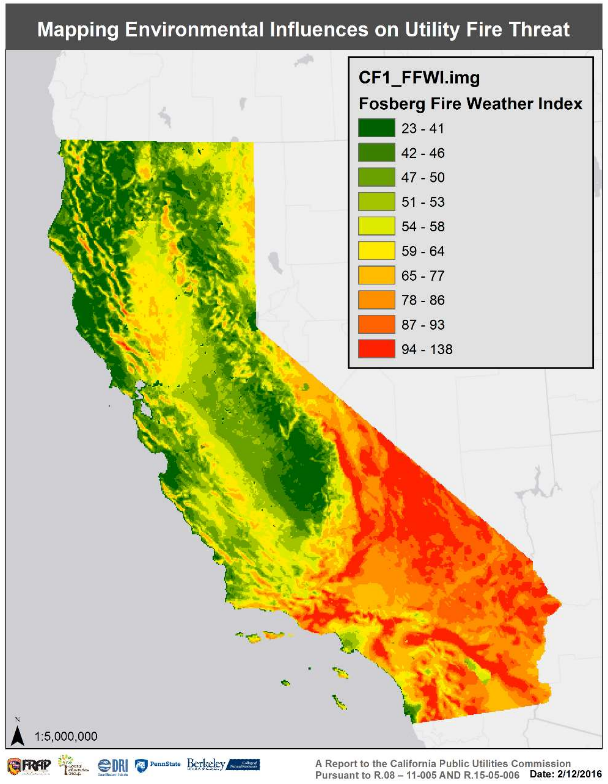


Source: Pacific Gas and Electric Company, "EPIC Final Report: 1.02 Energy Storage for Distribution Operations," June 20, 2017. Data series labels have been modified by Lumen.

Outage Mitigation Value

- **Review operations of distributed & customer-sited storage projects during historical outage events**
  - Consider only "upstream" outages that can be mitigated
- **Estimate outage reduction value based on:**
  - Storage discharge during outage event
    - *May also count co-located solar MWh if it would have been disconnected during outages*
  - Mix of electricity customers downstream from the storage facility
  - Assumed value of lost load (VOLL) for each customer and outage type

Public Power Safety Shutoffs



Starting in 2017, California IOUs implement targeted extended outages (Public Power Safety Shutoffs) to mitigate short-term wildfire risk.

Image source: Sapsis, David, et al., "Mapping Environmental Influences on Utility Fire Threat," February 16, 2016, Figure 10.

Bulk Grid Outages

Emergency notifications

	Transmission Emergency Declared for any event threatening or limiting transmission grid capability, including line or transformer overloads or loss.
Stage 1 Emergency	Contingency Reserve shortfalls exist or forecast to occur. Strong need for conservation.
Stage 2 Emergency	The ISO has taken all mitigating actions and is no longer able to provide its expected energy requirements. Requires ISO intervention in the market, such as ordering power plants online.
Stage 3 Emergency	The ISO is unable to meet minimum contigency reserve requirements, and load interruption is imminent or in progress. Notice issued to utilities of potential electricity interruptions.

The California ISO may order load interruptions under a Stage 3 Emergency due to extreme constraints on the system, as seen in August 2020.

Image source: California Independent System Operator, "System Alerts, Warnings and Emergencies," Fact Sheet, 2018.

Customer Bill Management

- **Customer bill impacts**
  - From time-of-use (TOU) and demand charge savings
  - Are not additive to grid-level benefits
  - Our focus is primarily to understand rate design-related synergies vs. barriers to meeting AB 2514 goals
- **Some overlap with annual SGIP impact studies**
  - We will rely on the SGIP impact studies for:
    - Sampling and SGIP data collection
    - Observed bill impacts, storage usage patterns (see right)
  - Incremental analysis will include:
    - Additional locational granularity on actual avoided costs
    - Hypothetical avoided costs under optimal dispatch
  - We will also aim to estimate impacts for non-SGIP customer-sited projects (88 MW online)

Selected Results from 2018 SGIP Impact Study*

FIGURE 4-31: NONRESIDENTIAL MONTHLY CUSTOMER BILL SAVINGS ($/KW) BY RATE GROUP AND PBI/NON-PBI

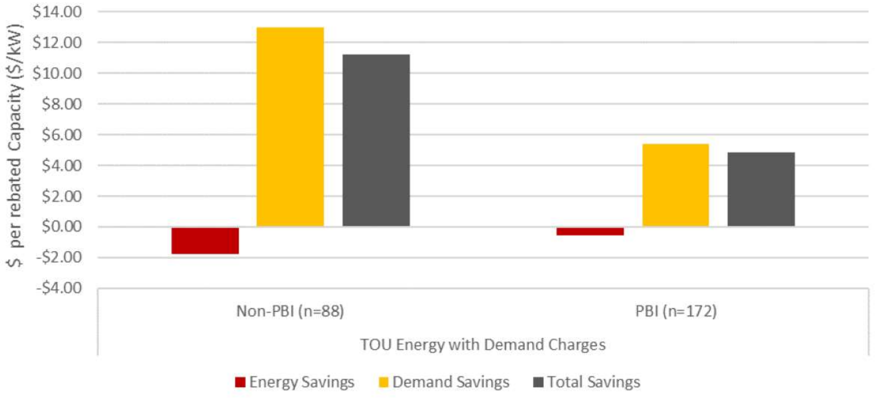
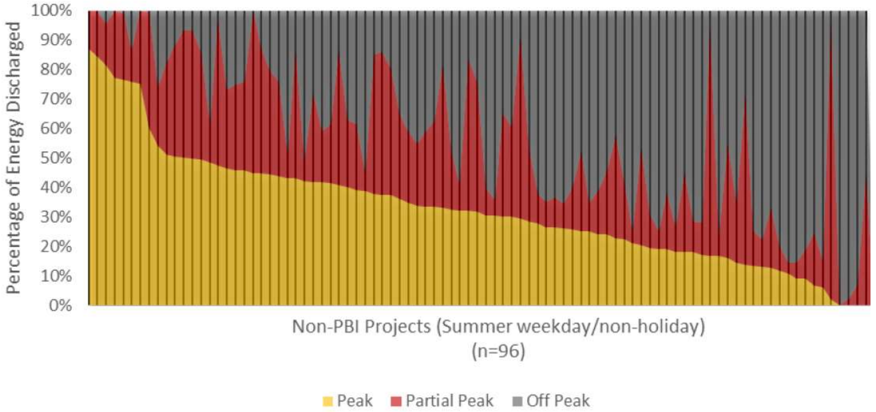


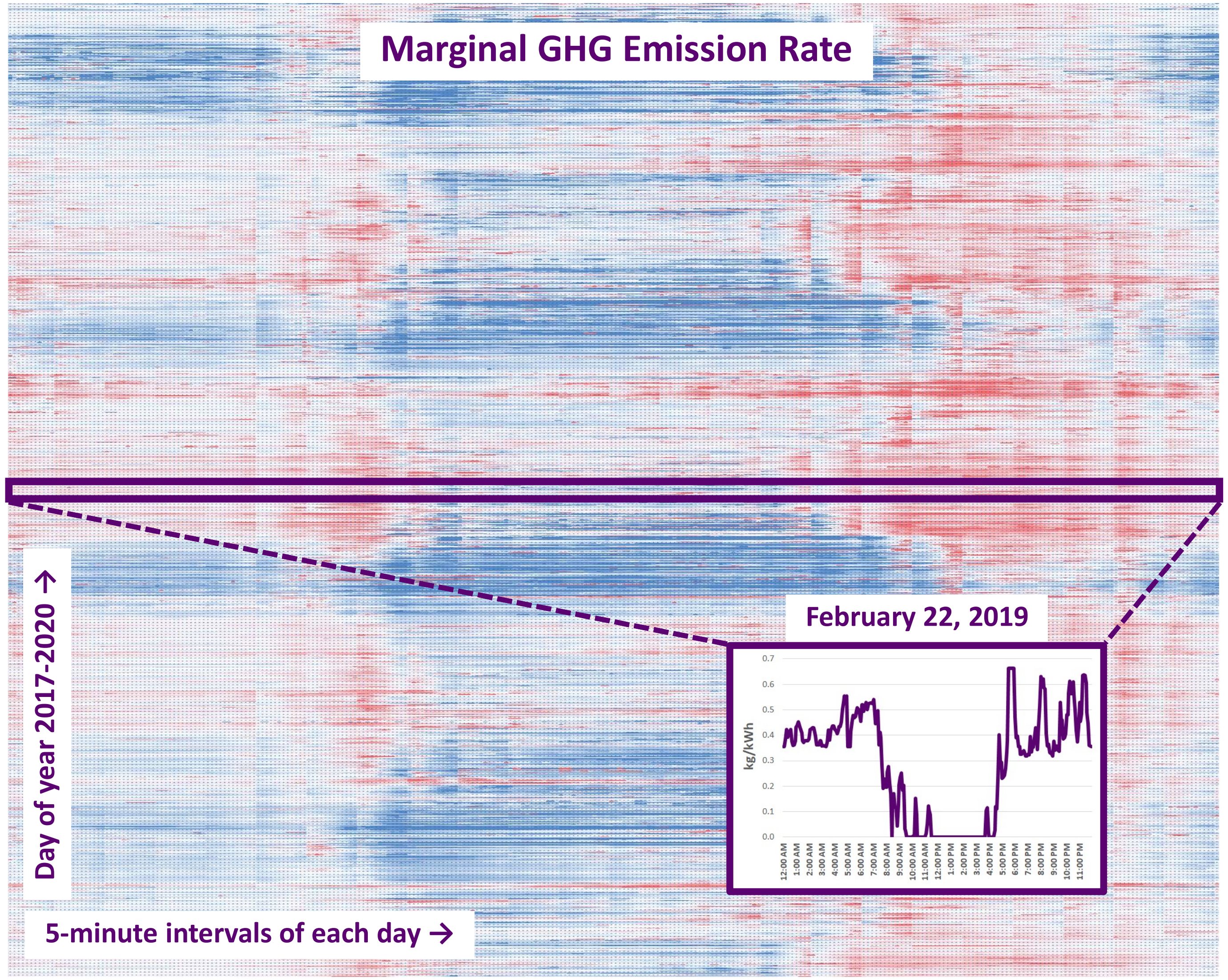
FIGURE 4-15: 2018 SGIP NONRESIDENTIAL NON-PBI PROJECT DISCHARGE BY SUMMER TOU PERIOD



Source: Itron, "2018 SGIP Advanced Energy Storage Impact Evaluation," January 29, 2020.
*Note: In the study, residential and non-residential customers are analyzed, and a number of performance statistics and customer impacts are reported.

Impact on GHG Emissions in Energy Market

- **System-level emission impacts of energy charge/discharge using marginal GHG emission rates**
  - Will utilize historical GHG signals developed for SGIP projects’ compliance with GHG reduction requirements
  - Zonal GHG signals created by WattTime using CPUC-approved methodology (D. 19-08-001)
- **Additional impacts from:**
  - Capacity-related attributes, such as avoiding output from local RMR units with higher GHG emissions than marginal rates
  - Renewable overbuild related to changes in curtailments



Avoided GHG Emissions Costs

Cap and Trade Market

$14–$18/tonne

- Short-term marginal cost of GHG abatement based on cap & trade market
- Captured in energy value calculations

	Hour 14	Hour 19	Avoided Cost
Storage	charge	discharge	
Marginal unit	efficient gas	inefficient gas	
Heat rate (Btu/kWh)	6,500	10,000	
Fuel cost ($/MMBtu)	$3.5	$3.5	
VOM ($/MWh)	$5	$5	
GHG rate (tonnes/MMBtu)	0.053	0.053	
GHG cost ($/tonne)	$15	$15	
Fuel + VOM cost ($/MWh)	$28	$40	$12
GHG cost ($/MWh)	$5	$8	$3
Marginal Energy Cost ($/MWh)	$33	$48	$15

Electricity Sector Targets

$40–$60/tonne

- Reflects abatement cost of meeting GHG reduction goals through add'l investments in electricity sector
- Based on RESOLVE GHG shadow price used in CPUC 2021 Avoided Cost Calculator (ACC)
- Internally consistent with CPUC's integrated resource planning
- Will only include "GHG Adder" above cap-and-trade allowance prices (remaining portion already in energy market value)

✓

Impacts reflect both short-term and long-term avoided costs

Portfolio Rebalancing

-$35/tonne

- Reflects long-run adjustments to electricity resource portfolio to meet emissions intensity targets
- A negative adjustment to avoided cost of GHG emissions
- Applicable to distributed energy resources that would increase load such as electrification measures
- Priced at GHG adder (see left)
- Included in CPUC 2021 Avoided Cost Calculator (ACC)

✗

Not applicable to energy storage

Social Carbon Cost

$51 or $76/tonne (2020)

- Social cost of CO2 emissions based on Biden Administration
- $51 at 3% discount rate
- $76 at 2.5% discount rate
- Wide range of views on what this value should be

✗

Not an incremental cost assuming that GHG targets will be met

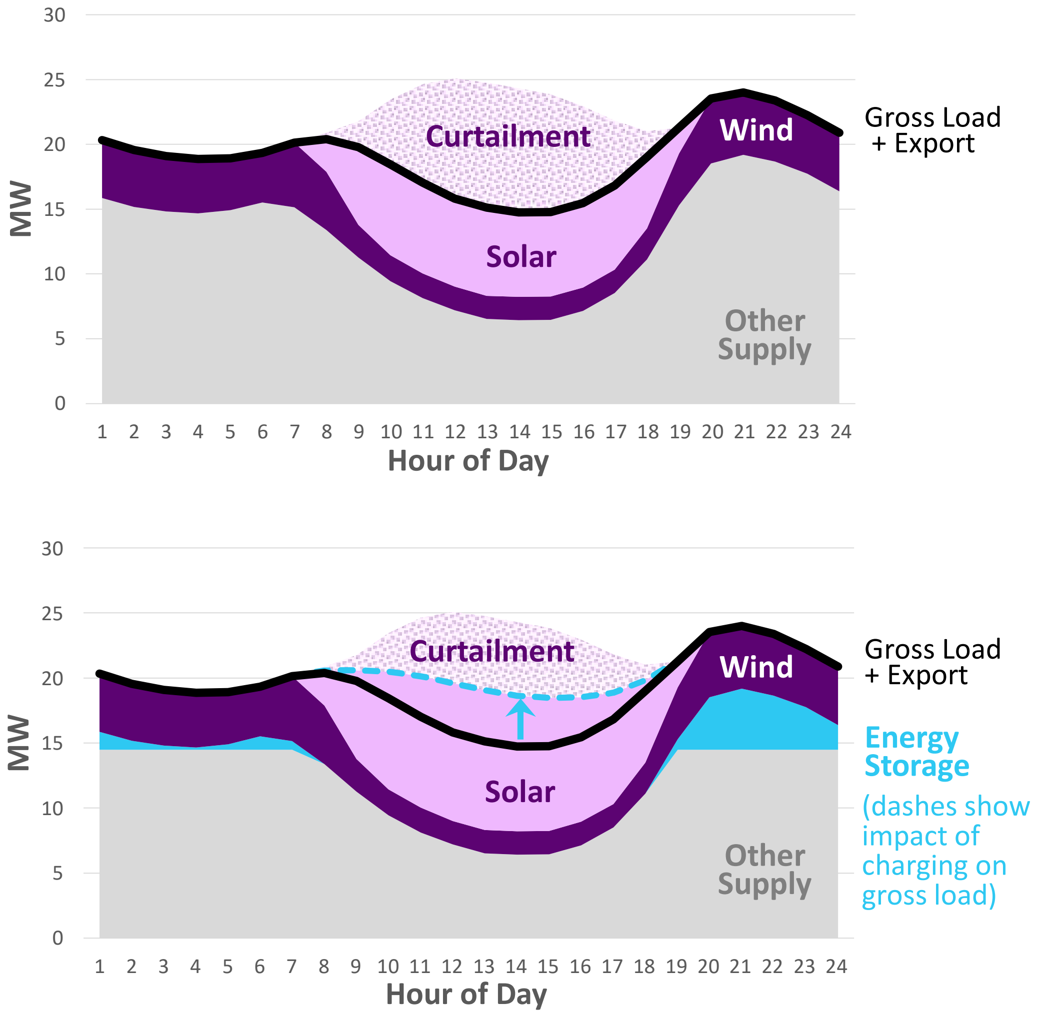
Q&A

—GHG IMPACTS

Impact on Renewable Curtailments

- **Analyze historical storage charge/discharge during periods with actual renewable curtailments**
  - Charging reduces curtailments by mitigating oversupply conditions
  - Discharging increases curtailments by exacerbating oversupply conditions
  - Important to differentiate curtailments driven by local vs. system-wide constraints
- **Lower renewable curtailments reduces the need (and costs) to procure additional resources to meet Renewable Portfolio Standard targets**

Illustration of Renewable Curtailments with and without Energy Storage

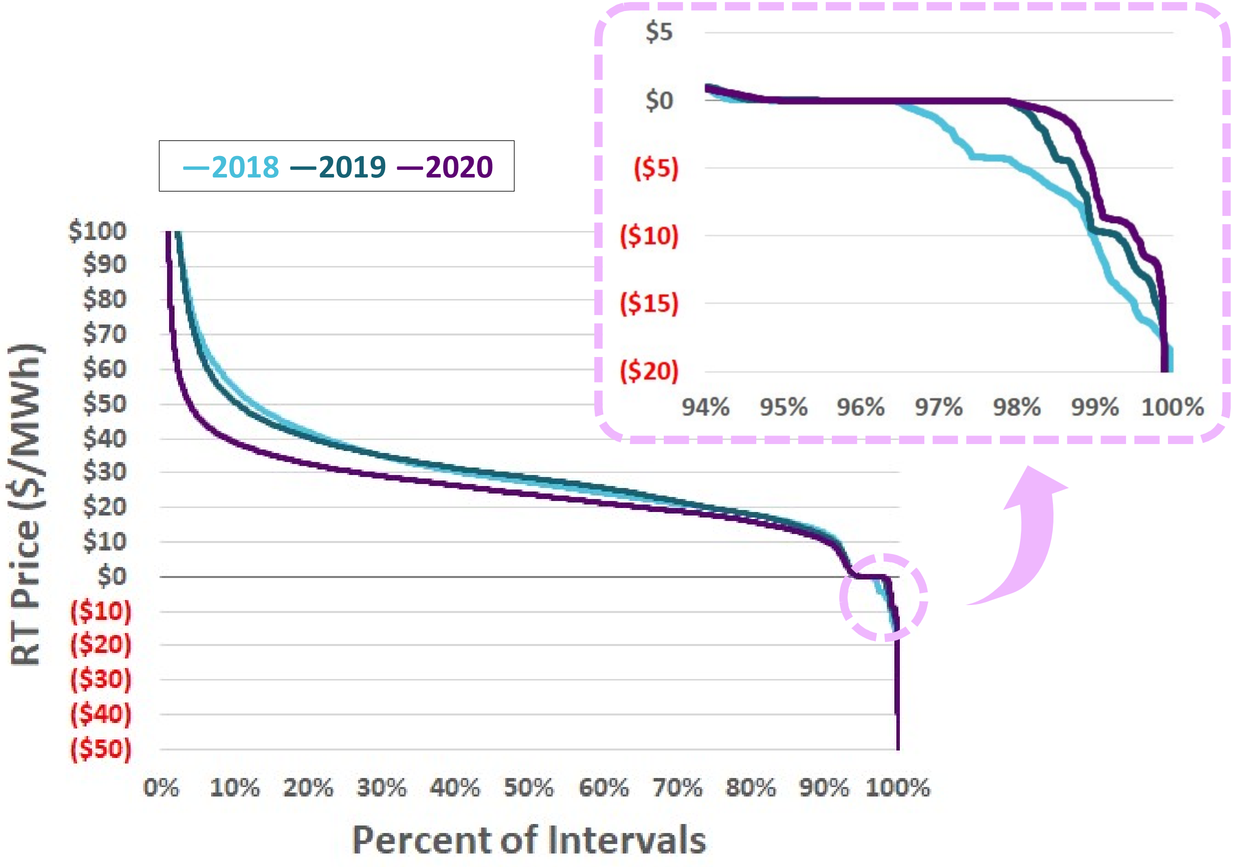


Avoided RPS Costs

- Lower curtailments reduce the need for overbuilding renewable resources++ to meet RPS targets
- Negative LMP includes opportunity cost for REC and ITC value; Will use $0 for these hours in energy value calculations to avoid double-counting
- Incremental RPS benefits based on estimated REC value = marginal renewable cost net of energy and capacity value
- Ratepayer impact net of tax credits; Total resource cost and social cost impacts grossed up for tax credits

Energy Price Duration Curve

(SP15 RT 5-min price)



Q&A

—RPS IMPACTS

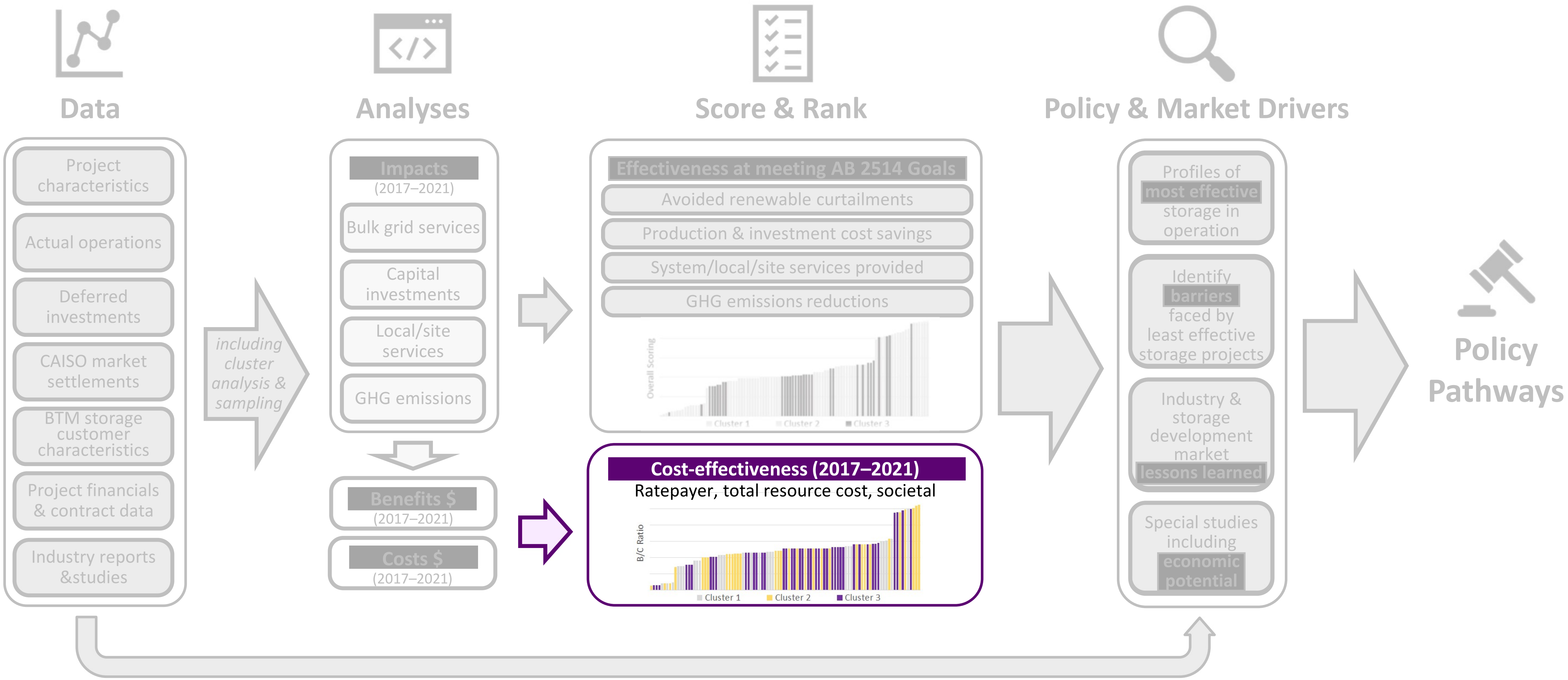
5-MINUTE BREAK

WILL RETURN AT 1:20 P.M. PDT

NEXT UP: COST-EFFECTIVENESS AND SCORING

Cost-Effectiveness

Cost-Effectiveness



Data

- Project characteristics
- Actual operations
- Deferred investments
- CAISO market settlements
- BTM storage customer characteristics
- Project financials & contract data
- Industry reports &studies

including cluster analysis & sampling

Analyses

Impacts
(2017–2021)

- Bulk grid services
- Capital investments
- Local/site services
- GHG emissions

Benefits $
(2017–2021)

Costs $
(2017–2021)

Score & Rank

Effectiveness at meeting AB 2514 Goals

- Avoided renewable curtailments
- Production & investment cost savings
- System/local/site services provided
- GHG emissions reductions

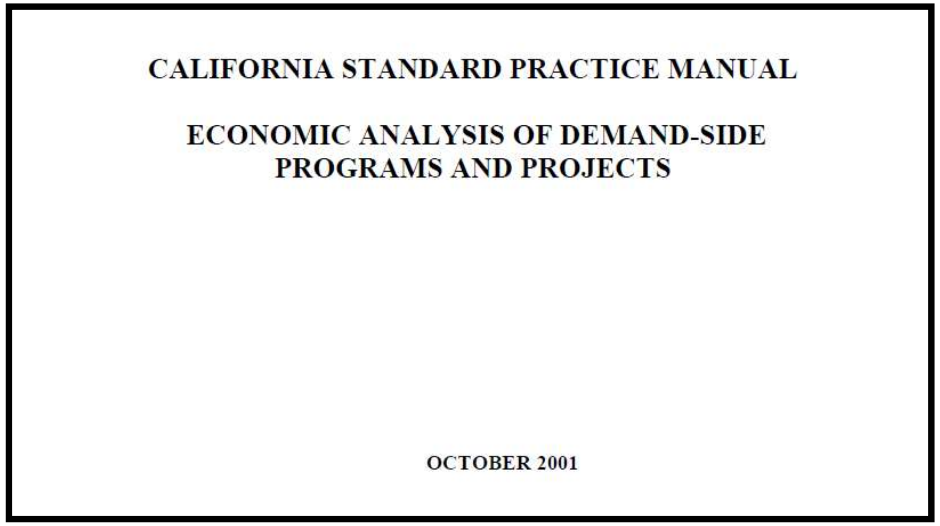
Cost-effectiveness (2017–2021)
Ratepayer, total resource cost, societal

Policy & Market Drivers

- Profiles of **most effective** storage in operation
- Identify **barriers** faced by least effective storage projects
- Industry & storage development market **lessons learned**
- Special studies including **economic potential**

Policy Pathways

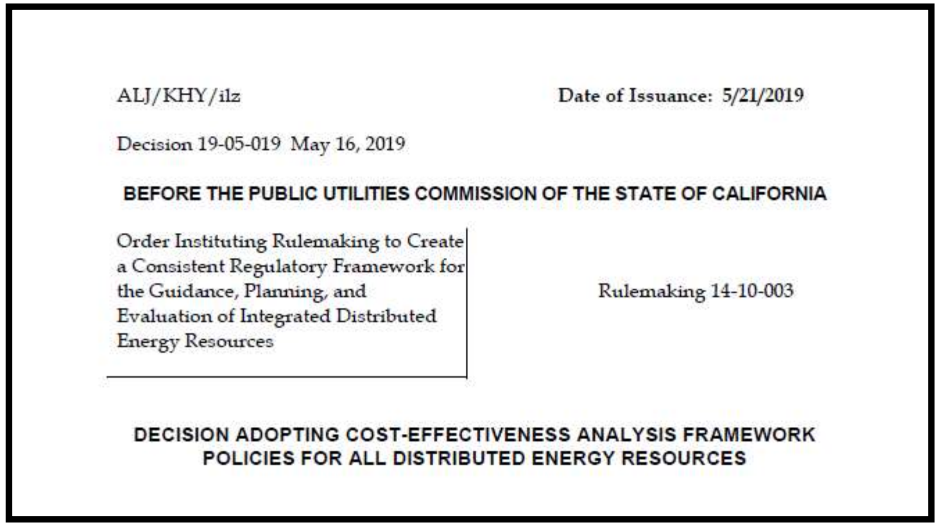
CPUC Standards for Cost-Effectiveness Analysis



CALIFORNIA STANDARD PRACTICE MANUAL

ECONOMIC ANALYSIS OF DEMAND-SIDE
PROGRAMS AND PROJECTS

OCTOBER 2001



ALJ/KHY/ilz Date of Issuance: 5/21/2019

Decision 19-05-019 May 16, 2019

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Create a Consistent Regulatory Framework for the Guidance, Planning, and Evaluation of Integrated Distributed Energy Resources.

Rulemaking 14-10-003

DECISION ADOPTING COST-EFFECTIVENESS ANALYSIS FRAMEWORK
POLICIES FOR ALL DISTRIBUTED ENERGY RESOURCES

- At the foundation: cost-effectiveness tests outlined in the California Standard Practice Manual (SPM)
  - Total resource cost; societal test as variant
  - Program administrator cost
  - Ratepayer impact measure
  - Participant cost
- Decision 19-05-019 reflects the CPUC current guidelines for applying the SPM
  - Applies to distributed energy resources
  - Requires total resource cost as primary test for all Commission activities, plus program administrator cost and ratepayer impact measure as secondary tests
  - Refines societal test and GHG emissions-related assumptions
  - Steps closer to a universal approach to resource evaluation across all domains

Cost-Effectiveness Perspectives

Cost-Effectiveness Test	Approach	
Participant Test	Measures quantifiable benefits and costs to the customers participating in a program	✗
Ratepayer Impact Measure (RIM) Test	Measures what happens to customer bills or rates due to changes in utility revenues and costs (only non-participant)	✗
Program Administrator Cost (PAC) Test	Measures net cost of a program as a resource option based on costs incurred by the utility or program administrator	✓
Total Resource Cost (TRC) Test	Measures net cost of a program as a resource option based on total costs, including both participants' and utility's costs ** Societal cost test is a variant of TRC test; Key differences: lower societal discount rate, effects of externalities (e.g., air quality) and social cost of CO_2 emissions*	✓

Participant vs. non-participant distinction doesn't apply to our study

For our study, this reflects total ratepayer impact excluding out-of-pocket participant costs

Cost-Effectiveness Tests Included in Our Study

		Total Ratepayer (PAC)				Total Resource (TRC)	
		Utility Owned	Contracted All Attributes	Contracted RA Only	Customer Owned		
Benefit Metrics	Energy and AS Value	✓	✓		✓	✓	Net of charging costs
	Capacity Value	✓	✓	✓	✓	✓	
	T&D Investment Deferral	✓	✓	✓	✓	✓	Only for distribution & customer domains
	Outage Mitigation					✓	Only for distribution & customer domains
	Customer Bill Savings						
	Avoided RPS Cost	✓	✓	✓	✓	✓	
	GHG Reduction Value	✓	✓	✓	✓	✓	Portion not already captured in E&AS value
Cost Metrics	Contract Payments		✓	✓			
	Capital Investment	✓			✓	✓	Ratepayer costs include only utility-funded portion of costs
	Fixed O&M	✓				✓	
	Variable O&M	✓				✓	Excludes charging cost (considered in E&AS value)
	Network Upgrade	✓	✓	✓		✓	
	IOU Imputed Debt		✓				Would be included only if passed onto ratepayers

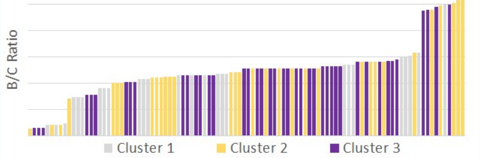
Benefit-Cost Ratios for Final Comparisons

Calculate monthly & annual values for each benefit and cost metric for the study period

Convert to 2022$ by adjusting for inflation using historical GDP deflator

Calculate capacity-wtd average ($/kW-year) costs and benefits over the study period

Benefit/cost ratios



- Retrospective benefits and costs so no PV/discount rate; will only adjust for inflation to show results in 2022$

- Results normalized for storage capacity so they can be compared across projects; capacity-weighted averages to account for changes of project capacity over time (e.g., due to staged installation, degradation)

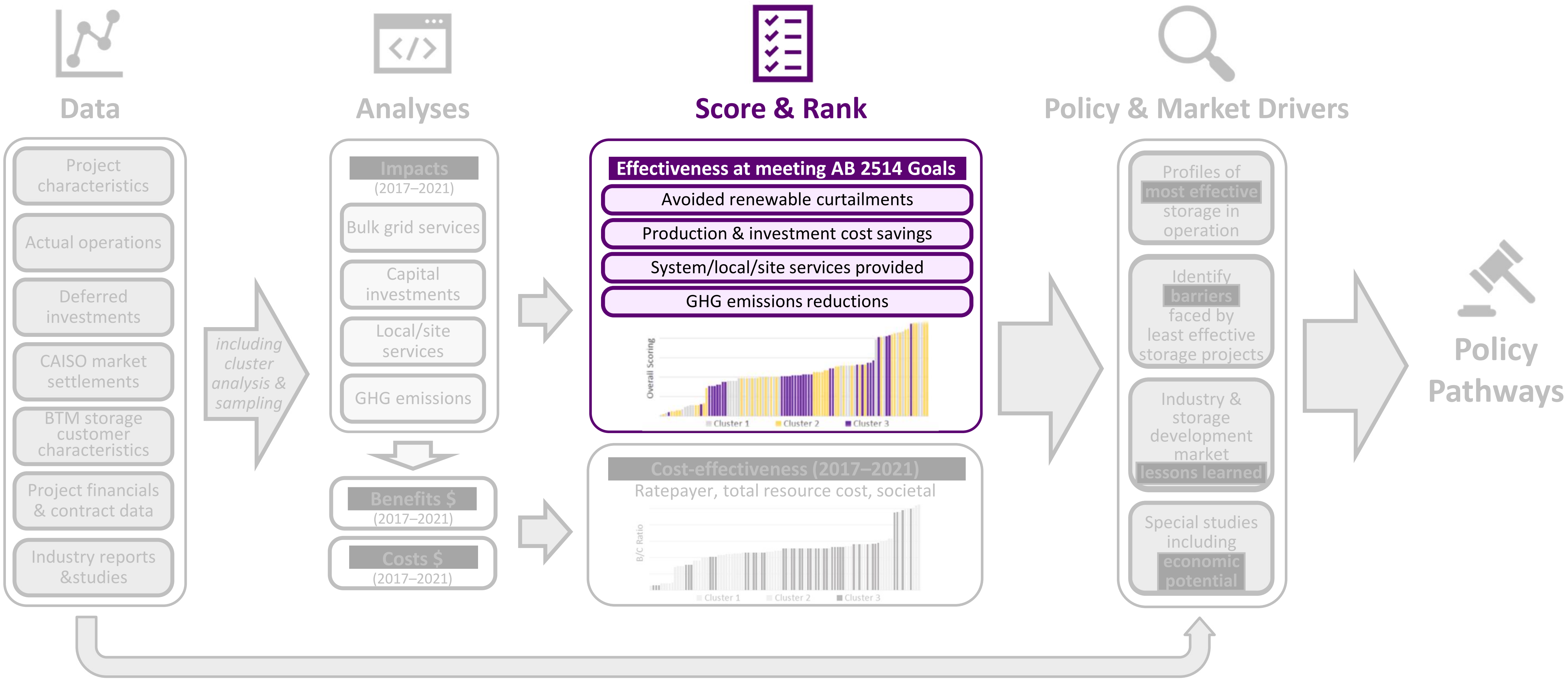
- Looking at only initial years of operation creates inherent bias against front-loaded cost recovery, so will run a sensitivity analysis for utility-owned projects, using levelized costs instead of revenue requirements

Q&A

—COST-EFFECTIVENESS

Scoring Towards AB 2514 Goals

Scoring Towards AB 2514 Goals



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Policy Pathways

Benefit Metrics and AB 2514 Goals

		Services that can be provided based on **Grid Domains**			*Services that can contribute towards* **AB 2514 Goals**		
	Services to Grid and Customers	**Transmission**	**Distribution**	**Customer**	**Grid Optimization**	**Renewable Integration**	**GHG Emissions**
Energy & AS Markets and Products	Energy	✓	✓	✓	✓	✓	✓
	Frequency Regulation	✓	✓	✓	✓	✓	*indirect*
	Spin/Non-Spin Reserve	✓	✓	✓	✓	✓	*indirect*
	Flexible Ramping	✓	✓	✓	✓	✓	
	Voltage Support	✓	✓	✓	✓	✓	
	Black Start	✓	✓	✓	✓		
Resource Adequacy	System RA Capacity	✓	✓	✓	✓		*indirect*
	Local RA Capacity	✓	✓	✓	✓		*indirect*
	Flexible RA Capacity	✓	✓	✓	✓	✓	*indirect*
T & D Related	Transmission Investment Deferral	✓	✓	✓	✓		
	Distribution Investment Deferral		✓	✓	✓		
	Microgrid/Islanding		✓	✓	*indirect*		
Site-Specific & Local Services	TOU Bill Management			✓	*indirect*		*indirect*
	Demand Charge Management			✓	*indirect*		
	Increased Use of Self-Generation			✓	*indirect*	✓	*indirect*
	Backup Power			✓	*indirect*		

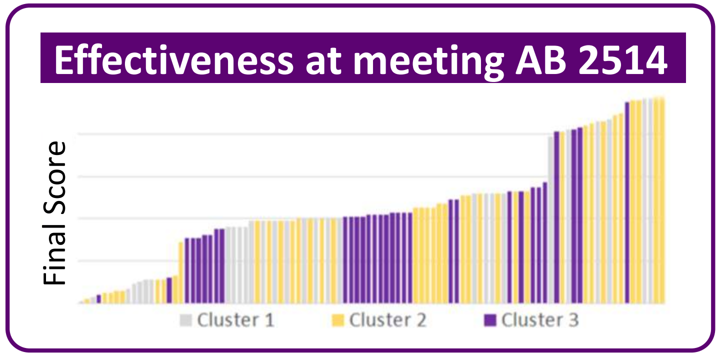
Impact Scoring & Ranking

	Energy Storage Project #1 (distribution domain)			
		Impact Metrics		
Services to Grid and Customers	**Possible Services**	**Grid Optimization** *percent of capacity used*	**Renewable Integration** *percent of capacity used*	**GHG Emissions** *tons/MWh of capacity installed*
Energy	✓	33%	10%	130
Frequency Regulation	✓	60%	60%	0
Spin/Non-Spin Reserve	✓			
Flexible Ramping	✓			
Voltage Support	✓			
Black Start	✓			
System RA Capacity	✓	100%		0
Local RA Capacity	✓			
Flexible RA Capacity	✓			
Transmission Investment Deferral	✓			
Distribution Investment Deferral	✓			
Microgrid/Islanding	✓			
Customer Bill Management				
Increased Use of Self-Generation				
Backup Power				
	Total	**193%**	**70%**	**130**
	Maximum Performance Across ALL Projects	200%	150%	160
	Normalized Score (0-100)	97	47	81
	Final Score (0-100)			**75**

Simple average across 3 impact metrics

- Purpose: assess effectiveness at meeting AB 2514 goals
- Impacts will be normalized based on total MW or MWh storage capacity
  - Shows key services provided
  - Indicates overall utilization of capacity
- Impact ranked against all projects
- Final score average of rankings
- Sort and graph scores for all projects (below)

Compare final scores of all projects



Effectiveness at meeting AB 2514

Q&A

—SCORING TOWARDS AB 2514 GOALS

Closing Remarks

Key Takeaways

- The core analysis of this study will focus on:
  - Actual energy storage operations, cost-effectiveness, and progress towards meeting stated purposes of optimizing the grid, integrating renewables, and/or reducing greenhouse gas (GHG) emissions
  - A broader energy storage market evolution within the state
- The CPUC, IOUs, and stakeholders have explored many avenues of energy storage development and benefit
  - Procurements and installations are accelerating
- We will consider a broad range of benefits across all domains
  - Following CPUC standards for cost-effectiveness
  - Using a scorecard approach to assess progress towards AB 2514 goals

Your Feedback

- Questionnaire posted on study website
  - lumenenergystrategy.com/energystorage
  - Please submit your responses by close of business June 9, 2021

- We seek your views on **important limitations and/or analytical factors** you would like the team to consider
  - Regarding our proposed energy storage cost-effectiveness and project scoring methodologies
  - Response on each topic or type of evaluation metric is limited to 1,000 characters
  - A summary of the feedback we receive will be included in the next workshop

Other Communication Channels

Go to lumenenergystrategy/energystorage for information on:

- Office hours with the study team
- How to share your insights on relevant industry reports and studies
- How to track our announcements and information we share
  - If you subscribe to our emails, please add energystorage@lumenenergystrategy.com to you address book

Next Steps

- **Stakeholders to provide feedback on this study's evaluation framework by close of business June 9, 2021**
- **We will review your feedback as we finalize the framework**
- **Workshop #2 in Q3 2021**
  - Summarize stakeholder feedback
  - Present final evaluation framework
  - Share initial observations on project use cases and operations

Thank You!