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Updated Energy Storage System Plan

CITY OF ANAHEIM
PUBLIC UTILITIES DEPARTMENT

July 2017

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Executive Summary

Background

This plan is an update to the City of Anaheim Public Utilities (APU) Department's 2014 Energy Storage System Plan (2014 ES Plan), including a revised energy storage (ES) procurement target to be achieved by December 31, 2021 and an evaluation of the viability and cost-effectiveness of the current ES technologies. As a not-for-profit public agency, APU is focused on serving the local community with reliable electric service while maintaining affordable rates for its customer-owners; therefore, any investment in energy storage resources must be done in a responsible, strategic manner.

In an effort to accommodate intermittent renewable resources such as solar and wind generators and maintain the reliability of the bulk electric system, Assembly Bill (AB) 2514 (Skinner, Chapter 469, Statutes of 2010) was signed into law on September 29, 2010. The statute requires all publicly owned utilities (POUs) to conduct an evaluation to determine appropriate targets, if any, for each utility to procure viable and cost-effective ES systems to be achieved by December 31, 2016, and a second target by December 31, 2021. The bill also requires that not less than once every three years (on or before October 1, 2017), the governing boards of all POUs shall re-evaluate their determinations of ES procurement targets to be achieved by December 31, 2021.

Since 2014, ES adoption has increased significantly with roughly 4 Gigawatts (GW) installed by the end of 2016 according to research by Bloomberg New Energy Finance. As such, APU has been monitoring the industry to determine how to incorporate projects into its system, without adversely affecting customer rates. Much of the ES development activity has been through Investor Owned Utilities (IOU), who have different rate recovery mechanisms than POUs; therefore, APU has been evaluating pilot projects to test financial viability, as well as public-private partnerships to leverage private investment that takes into consideration the rapid speed of technology advancement.

APU's activities since the 2014 ES procurement targets evaluation, include commissioning professional studies by third-party consulting firms (Appendix A: Leidos Study and Appendix B: DNV GL Study), conducting site visits to evaluate different ES installations, and evaluating different ES projects and pricing proposals. APU also conducted preliminary analyses of wholesale electricity market price data to identify potential value streams for ES.

Findings

The following findings were reached after conducting two professional studies and evaluating specific ES projects for use within Anaheim:

1. **<u>The procurement target for December 31, 2021 is a 1 megawatt (MW) pilot project at Harbor Substation:</u>** APU is in the process of planning for a 1 MW ES pilot project at its new Harbor Substation (Figure 1), which is located in a strategic load

center serving high density developments in the Platinum Triangle, which is generally bounded by the 5 and 57 freeways and includes the Angel Stadium and Honda Center venues. Harbor Substation is currently being designed, and will include provisions for a 1 MW ES pilot system that is fully dispatchable and integrated with APU's other power resources. The Harbor Substation installation will allow APU staff to gain first-hand experience and validate the conceptual assumptions for future ES deployments, whether through APU procurement or by private corporations interconnected to APU's local grid.

Figure 1. Harbor Substation Rendering

2. **<u>The next procurement target is a 10 MW ES installation at Canyon Power Plant by December 31, 2026</u>:** Canyon Power Plant (Canyon) is a 200 MW gas-fired peaking power plant that provides fast start-up to mitigate ramping when solar generation is typically coming off-line (Figure 2). Anaheim is currently evaluating the most appropriate application of ES at Canyon, which may be a stand-alone system, or coupled with existing generating facilities in a hybrid manner that combines the speed of batteries with the efficiency of gas turbines. As battery ES technologies continue to mature and gain higher market share, different applications and control systems will be implemented and tested in California, allowing Anaheim to apply the solution best suited to its resource needs. With Anaheim's own testing at Harbor Substation being completed, Anaheim expects to have more data and experience on how to optimize the operation of ES and demonstrate value to Anaheim customers prior to seeking Anaheim City Council approval on future procurements and California Energy Commission (CEC) authorization as the Canyon site is within CEC's jurisdiction. A unique aspect of the Canyon Power Plant is that the existing 9-acre parcel has available space that was initially intended for future expansion of thermal resources; however, with the proliferation of intermittent renewables, APU now anticipates utilizing the available space for ES technology.

Figure 2. Canyon Power Plant

3. **<u>ES may be an area of opportunity for APU:</u>** APU is committed to collaborating with the California Independent System Operator (CAISO), other State agencies, and utilities to preserve and improve the reliability of the electric grid system. APU is also committed in its holistic view that the procurement of reliable renewable resources, in a balanced manner, will continue to help the CAISO mitigate the need for additional flexible ramping capacity, in response to the overabundance and variability of wind and solar generation on the grid today. Although there is no immediate need for distribution infrastructure services or upgrade deferrals because Anaheim is essentially built-out and has a robust undergrounding program, over the next decade, ES may become a prominent part of APU's resource assets. The prominence of ES systems in Anaheim will also be dependent on the proliferation of utility-scale renewables as well as customer-owned distributed energy resources such as behind-the-meter solar and fuel cell systems that may require realignment of rate recovery mechanisms for fixed costs, adjustment of Time-of-Use (TOU) rates, and implementation of new demand response programs.

4. **<u>ES may be viable and cost-effective for the provision of ancillary services:</u>** Based on APU's analyses, ES currently has a limited effect in its ability to shift energy from one time period to another in the CAISO wholesale electricity market. However, APU studied the potential for ES to provide ancillary services. The costs of regulation and spinning reserves in the CAISO market for APU have increased significantly from 2014 to 2016. Regulation-up and regulation-down services cost approximately twice as much from 2014 to 2016, and spinning reserve cost increased by more than 20%. Since ancillary services are much smaller in megawatt volume compared to energy products, current battery ES technologies, particularly the Lithium-Ion technology, may be a potentially viable and cost-effective means to self-provide ancillary services. The proposed 1 MW ES pilot project at Harbor Substation and continued monitoring of ancillary service costs will help determine the feasibility of these benefits for future ES projects, and whether or not market conditions dictate potential acceleration of upcoming projects.

5. **APU is also considering other ES project proposals:** APU is currently reviewing three additional ES project proposals, the Yorba Battery Storage Project, the San Vincente ES Facility, and the Hoover Pumped Storage Project. These project proposals are intrinsically different in ES technology, application, and ownership structures. The project proposals will be evaluated to determine potential benefits to Anaheim customers.

Conclusions

From the findings above, APU concludes and recommends the following:

1. Adoption of ES procurement targets for December 31, 2021 at 1 MW for the Harbor Substation ES pilot project to plan for the 10 MW ES installation at the Canyon Power Plant by December 31, 2026; and,

2. Additionally, APU will continue to evaluate ES proposals, including the Yorba Battery Storage Project, the San Vincente ES Facility, and the Hoover Pumped Storage Project; and,

3. APU will continue to evaluate ES technologies and opportunities by monitoring other utility projects and collaborating with various utility industry and public agency groups.

Section 1: Introduction

APU's development of the 2014 ES Plan was in response to mandates established by AB 2514, an energy storage bill that was signed into law on September 29, 2010. AB 2514 requires all utilities statewide, which serve more than 60,000 customers, to analyze and adopt policies for the procurement of ES. As a POU with more than 115,000 electric customers, APU is required to comply with the bill.

This plan serves as an update to the 2014 ES Plan and provides the findings and recommendations from APU's evaluation efforts related to ES. Specifically, this plan discusses the regulatory requirements under AB 2514 and APU's activities in analyzing the viability and cost-effectiveness of current ES technologies.

Requirements of Assembly Bill 2514: Energy Storage Systems

AB 2514 seeks to ensure that the State's electricity system, including the grid and electricity market itself, are structured to support ES such that multiple benefits can be realized to the extent they exist. To achieve the goal of integrating ES into the existing electric grid, AB 2514 laid out a process and timeline for the evaluation and implementation of ES and the associated policies, as well as defining energy storage for purposes of the bill's implementation. Specifically, the bill directed the California Public Utilities Commission (CPUC) to hold proceedings for all IOUs and required the governing boards of all POUs to conduct an evaluation to determine appropriate targets, if any, for each utility to procure viable and cost-effective ES systems.[1]

Applicable Energy Storage Systems

AB 2514 defines characteristics and purposes that must be met by an ES system for it to be considered a valid ES use under the bill. As a not-for-profit public agency, APU is required by its City Charter to recover its direct costs from ratepayers, and as such, significant investments in ES technologies require sufficient due diligence to quantify and demonstrate value to customers and avoid the potential for stranded investments. With the accelerated deployment of ES projects since 2014 and technological advancement in the industry, APU is proceeding with testing, analysis, and planning for ES as part of its transformation of power resources to clean, sustainable resources.

In addition to being viable and cost-effective, the ES systems must perform at least one of the following functions[2]:

- Use mechanical, chemical, or thermal processes to store energy that was generated at one time for use at a later time.
- Store thermal energy for direct use for heating or cooling at a later time in a manner that avoids the need to use electricity at that later time.

[1] Section 2836.6 of AB 2514, Skinner, Energy Storage Systems.
[2] Section 2835(a)(4) of AB 2514.

- Use mechanical, chemical, or thermal processes to store energy generated from renewable resources for use at a later time.
- Use mechanical, chemical, or thermal processes to store energy generated from mechanical processes that would otherwise be wasted for delivery at a later time.

It further requires that the ES system accomplish one or more of the following purposes[3]:

- Reduce emissions of greenhouse gases (GHG),
- Reduce demand for peak electrical generation,
- Defer or substitute for an investment in generation, transmission or distribution assets, or
- Improve the reliable operation of the electrical transmission or distribution grid.

Overarching these specific requirements is the intent of the bill outlined in the findings and declarations. ES systems are expected to:[4]

- Integrate intermittent generation from eligible renewable energy resources into the reliable operation of the electric system.
- Allow intermittent generation from eligible renewable energy resources to operate at or near full capacity.
- Reduce the need for new fossil-fuel powered peaking generation facilities by using stored electricity to meet peak demand.
- Reduce purchases of electricity generation sources with higher emissions of greenhouse gases.
- Eliminate or reduce transmission and distribution losses, including increased losses during periods of congestion on the grid.
- Reduce the demand for electricity during peak periods and achieve permanent load-shifting by using thermal storage to meet air-conditioning needs.
- Avoid or delay investments in distribution system upgrades.
- Use energy storage systems to provide the ancillary services otherwise provided by fossil-fueled generating facilities.

Timing Requirements

AB 2514 included deadlines to ensure that utilities undertake the efforts envisioned by the bill, and that the processes and results are made available to the public in a manner as transparent as possible. The following milestones have been reached, and the remaining deadlines are applicable to APU[5]:

1. In April 2012, the Anaheim City Council initiated a process to determine an appropriate target, if any, for APU to procure viable and cost-effective energy storage at the recommendation of the Anaheim Public Utilities Board. As part of the

[3] Section 2835(3) of AB 2514.
[4] Paraphrased from Section 1 of AB 2514.
[5] Paraphrased from AB 2514.

process, APU considered a variety of possible policies to encourage the cost-effective deployment of energy storage systems, including refinement of existing procurement methods to properly value energy storage systems.

2. In August 2014, the Anaheim City Council determined, consistent with APU's evaluation, that the adoption of procurement targets for ES systems for either December 31, 2016 or December 31, 2021 was not appropriate due to lack of cost-effective ES system options. APU submitted its Energy Storage Resolution No. 2014-146, Staff Report, and the 2014 ES Plan to the CEC. All filed documents were published on the CEC website at http://www.energy.ca.gov/assessments/ab2514_reports/City_of_Anaheim/.
3. In November 2016, APU filed its 2016 Compliance Report to the CEC, stating that consistent with the 2014 ES procurement targets determination, it has not made any new ES commitments to date. This report was also published on the abovementioned CEC website.
4. Once every three years (on or before October 1, 2017), the Anaheim City Council is required to reevaluate the determinations made by the previous processes.
5. APU is required to report to the CEC regarding any energy storage system procurement targets and policies adopted by the Anaheim City Council during the initial and subsequent evaluations.
6. By January 1, 2022, APU is required to submit a report to the CEC demonstrating that it complied with the ES System procurement targets or ES system procurement policies adopted by the Anaheim City Council. The report, with confidential information redacted, shall be made available to the public by the CEC and/or APU on their respective websites.

APU continues to evaluate advances in ES technologies and closely monitors other utilities' investments in ES systems. APU also participates in the Southern California Public Power Authority's (SCPPA) Energy Storage and Renewable Working Groups to actively review new and existing technologies for any joint ES pilot project opportunity, and evaluates proposals in SCPPA's annual solicitation for new resources. The next sections discuss APU's activities since the 2014 ES procurement targets evaluation and APU's ES strategic plan.

Section 2: Outlook for Energy Storage in Anaheim

This section reviews the current ES status in Anaheim and the changes since the 2014 ES procurement targets evaluation. Additionally, it discusses the outlook for ES in Anaheim.

Current ES Systems Operating in Anaheim

In the 2014 ES Plan, APU discussed and provided an overview of the exiting ES systems operating in the City of Anaheim, of which there were over 3 MW (3,150.20 kW) of Thermal Energy Storage (TES) systems installed. These TES systems chill water or generate ice at night when electricity demand is typically lower and then use the chilled water or ice to cool the air during the day. Given then proliferation of utility scale solar generation in California, the effectiveness of TES is not the same as initially intended. By shifting air-conditioning load from the afternoon to early morning hours, TES does not necessarily help to store the oversupply of solar energy now on-line within the CAISO control area, especially in the Spring when there is an overabundance of solar and hydro generation.

Table 1 below shows current ES projects installed in Anaheim.

Table 1: ES Systems Operating in the City of Anaheim

Project	Date Operational	On-Peak kW Shifted
Small Scale Systems		
Fire Station #8	2004	6.70
Customer Sited Systems	2007	125.11
Customer Sited Systems	2008	93.41
Customer Sited Systems	2009	26.82
Canyon Power Plant	2012	23.16
Total of Small Scale System		**275.20**
Large Scale Systems		
Customer Sited Systems	2011	2,356.00
Anaheim West Tower	1992	519.00
Total of Large Scale Systems		**2,875.00**
Total Installed kW of Energy Storage		**3,150.20**

Changes since the 2014 ES Procurement Targets Evaluation

There have been several changes since 2014 resulting in factors influencing the outlook for ES in Anaheim:

- Technology – Costs of ES systems, especially Lithium-Ion batteries, have come down. The battery storage market is becoming more competitive, resulting in the rapid technological advancement and also bankruptcies of several emerging technology startups. Figures 3-5 illustrate the projected cost reductions for different ES technologies.[6]

[6] Det Norske Veritas and Germanischer Lloyd (DNV GL), ES Study for NCPA and SCPPA, May 2017.

Figure 3: Energy Storage Equipment Cost Trends

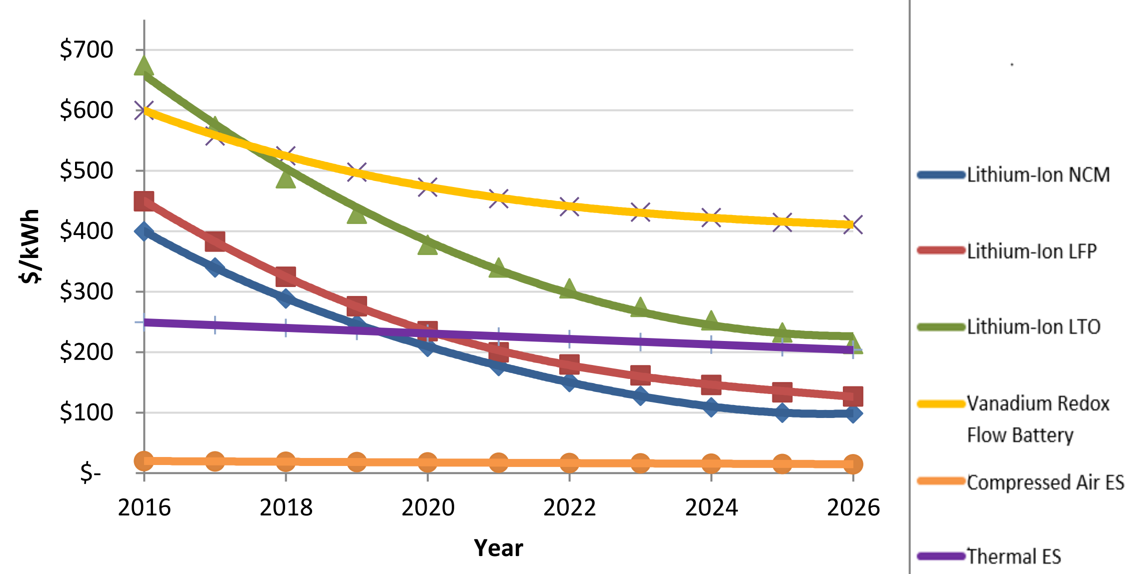
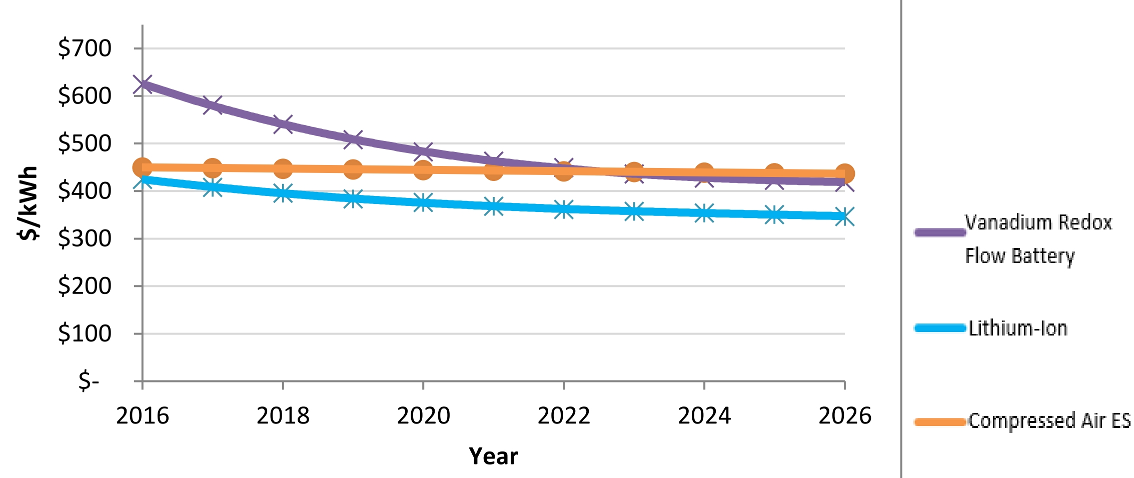
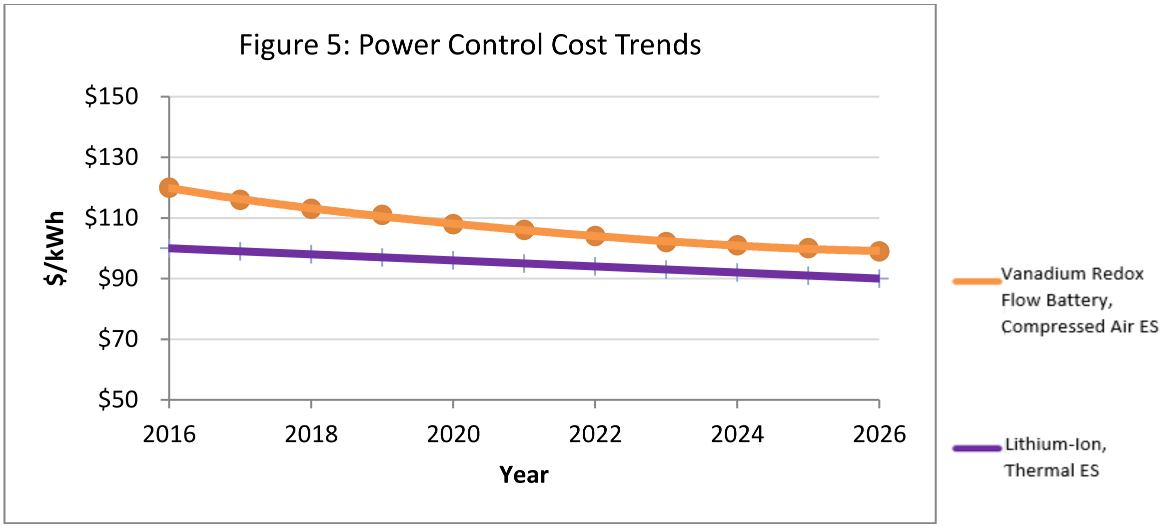


Figure 4: Power Conversion Equipement Cost Trends





- Grid condition – California has significantly more renewable energy resources each year. As Table 2 below indicates, the CAISO's solar energy production peaks have doubled in less than three years. These solar resources are intermittent in nature and cease output around late afternoon to early evening, contributing to the low net minimum load conditions. To balance energy supply and demand on the grid, the CAISO needs fast response resources to accommodate the steep ramp in demand in the late afternoon hours.

Table 2: CAISO Solar Energy Production Peaks[7]

Date	Time	Peak Production MW
4/21/2017	12:08 PM	9,868
3/2/2017	10:07 AM	9,066
9/14/2016	12:06 PM	8,545
8/9/2016	12:29 PM	8,375
5/11/2016	12:33 PM	7,755
3/16/2016	11:11 AM	6,835
9/17/2015	2:01 PM	6,506
8/21/2015	12:23 PM	6,446
7/13/2015	1:28 PM	6,299
4/28/2015	1:27 PM	6,038
3/6/2015	10:19 AM	5,812
9/29/2014	2:18 PM	4,903

[7] California Independent System Operator, *CEO Reports*, website, http://www.caiso.com, July 11, 2017.

- Aliso Canyon gas storage facility leak – Southern California Gas Company's underground gas storage facility in Los Angeles had a leak in 2015, resulting in continued electrical reliability risks in the Los Angeles area basin.
- Legislation and public opinion – Senate Bill 350 requires more renewable energy resources, which elevates attention on topics such as energy storage, distributed generation, and demand response. Based on APU's recent Integrated Resources Plan Customer Survey, customers in general are supportive of renewable resources, and about one-third of large business customers with interruptible on-site power generation would support incentivized demand response programs. However, customers are concerned about future rate impacts resulting from additional mandates.

Outlook for ES in Anaheim

APU is committed to collaborating with the CAISO, other State agencies, and utilities to preserve and improve the reliability of the electric grid system. Historically, APU has recognized the need for non-intermittent and reliable renewable resources and invested in baseload renewable resources such as biomass & waste (including landfill gas) and geothermal, which constitute more than 50% of APU's renewable power mix.[8] To ensure minimal impact to the grid, APU has also carefully chosen renewable wind resources from diverse geographic regions with complimentary energy production profiles. For example, APU's wind resources in Wyoming on average generate renewable energy at different times, and seasons, than when APU's wind resources in Palm Springs, CA are generating. APU has pursued a holistic strategy of procuring reliable renewable resources in a balanced manner that has helped the CAISO to mitigate the need for additional flexible ramping capacity in response to the variability of wind and solar generation.

ES may be an area of opportunity for APU to continue its strategic plan for a balanced, sustainable, cost-effective supply portfolio. Although there does not appear to be an immediate need for distribution infrastructure services or upgrade deferrals, over the next decade, ES may become a prominent part of APU's resource mix to mitigate renewable intermittency and address ancillary services requirements. As such, APU is planning to test ES at Harbor Substation and has the available space at Canyon Power Plant. Concurrently, APU will continue evaluating different ES technologies and ownership structures that provide the most value to customers.

[8] California Energy Commission, *Utility Annual Power Content Labels for 2015*, website, http://www.energy.ca.gov/pcl/labels/2015_labels/Anaheim.pdf, May 15, 2017.

Section 3: Energy Storage Deployment Plan

As mentioned, APU plans to implement a near-term plan to install and test a 1 MW ES pilot at the proposed Harbor Substation by December 31, 2021. By integrating the ES system into APU's power supply portfolio, it will provide the opportunity to test dispatch capabilities to address CAISO market opportunities as intermittent resources continue to proliferate in California.

A future ES installation is earmarked at the Canyon Power Plant, which is a 200 MW facility located on a 9 acre site in an industrial area in Anaheim with no residential areas nearby. It provides electricity to meet Anaheim's peak demand, enhance system reliability, and reduce APU's reliance on out-of-state resources. The Canyon Power Plant has available space to support ES resources with the optionality of a hybrid system combined with gas turbine technology, or stand-alone batteries.

The following section outlines APU's internal analyses and external professional studies, together with its strategic plan for the development of 10 MW ES at the Canyon Power Plant by December 31, 2026.

Potential ES Applications

To determine the appropriate application for ES at the Canyon Power Plant, APU researched the viability and cost-effectiveness of utilizing the ES as different products in the CAISO wholesale electricity market.

Energy Time-Shift

The first type of product is energy. The ES system would be utilized to perform energy time-shift, which means shifting energy from one time period to another in the market. It would allow APU to react to price signals from the wholesale market by charging the ES system during low-priced hours and then quickly reacting to high energy prices by discharging during high-priced hours.

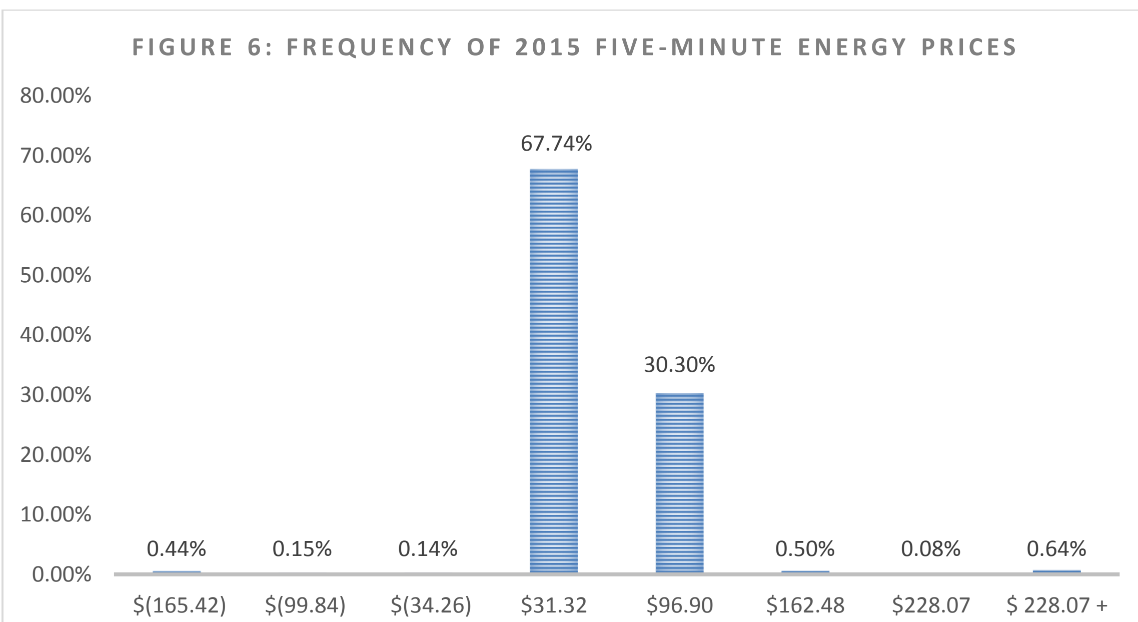
In 2016, APU engaged Leidos, a global consulting firm that specializes in energy solutions and utility planning, to assess the potential for various distributed generation technologies, including ES systems, to be installed at the Canyon Power Plant (see Appendix A). Leidos employed a three-step approach: site evaluation, technology prioritization, and business case assessment. Leidos identified that there is sufficient space at the Canyon Power Plant for a 12,500 kW / 50,000 kWh capacity battery ES system at an estimated installed capital cost of $38,363,000. While technically feasible, current market prices do not support the business case, as Leidos concluded that bidding into the CAISO energy market would produce a negative net present value (NPV) for the project lifetime. Based on the analysis, APU concluded that ES advancement needs to continue to lower capital costs and CAISO market conditions need to support ES systems in order to justify investment in large scale systems in Anaheim.

APU conducted an additional analysis of how the ES would react to price signals if it were bid into the CAISO wholesale market for energy based on the 2015 and 2016 real time market prices:

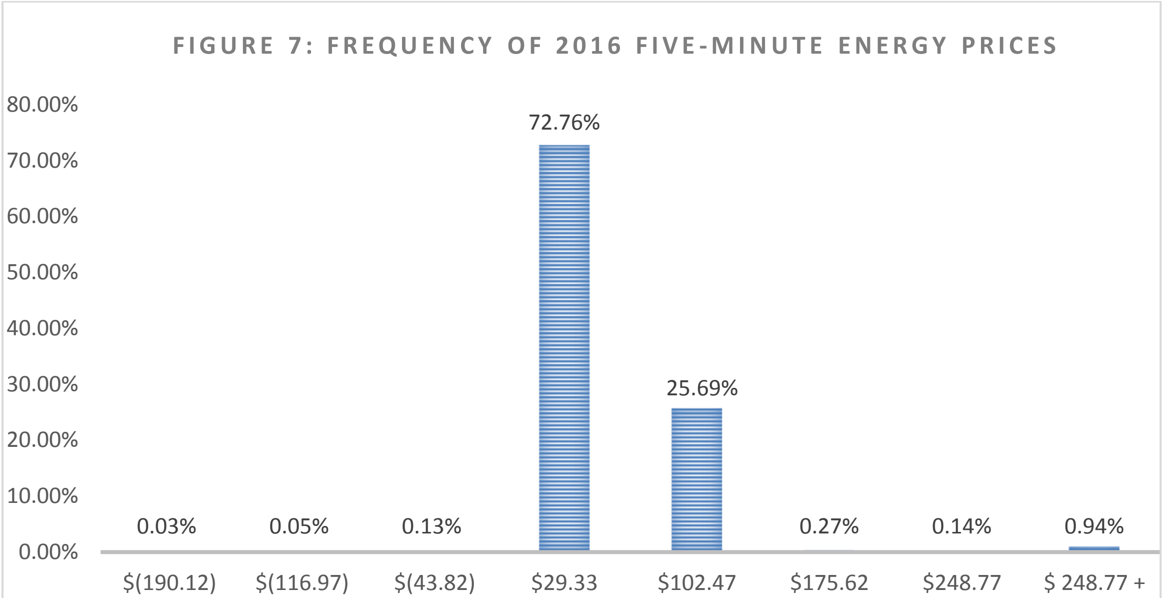
Table 3: Real Time Market Price Analysis

	2015	2016
Average of the five-minute real time prices per MW	$31.32	$29.33
Percentage of the five-minute intervals that are below the annual average price (meaning that the ES could potentially charge during these intervals)	68%	73%
Average price per MW of intervals that are below the annual average price	$19.92	$17.17
Percentage of the five-minute intervals that are above the annual average price (meaning that the ES could potentially discharge during these intervals)	32%	27%
Average price per MW of intervals that are above the annual average price	$56.09	$62.15

Although there appears to be some opportunities for electric energy time-shift, these prices do not present cost-effective uses for energy bids, based on the Lithium-Ion battery industry cost trend in 2015 (levelized cost $321 to $658 per MWh) and 2016 (levelized cost $285 to $581 per MWh) for the peaker plant replacement use case.[9] APU expects the cost will continue to drop in the coming years, and approach cost effectiveness.



[9] Greentech Media, *Storage Costs Come Down Across Technologies and Applications According to Lazard Report*, website, https://www.greentechmedia.com/articles/read/energy-storage-costs-lcos-lazard-lithium-ion-flow-batteries, December 19, 2016.



Ancillary Services

APU subsequently researched the potential in utilizing the ES for ancillary services products by conducting an analysis on the products that APU regularly procures from the CAISO wholesale market, as depicted in Tables 4, 5, and 6 below. The costs of these ancillary services products increased significantly in 2016. Regulation-up and regulation-down services cost approximately twice as much from 2014 to 2016, and spinning reserve cost increased by more than 20%. Since ancillary services are much smaller in megawatt (MW) volume compared to energy products, ES may become a viable source of ancillary services for APU over the next decade if the trend of price increase continues. Table 7 shows APU's actual cost of ancillary services per MWh of load for the past three fiscal years and the forecast cost for the next decade. APU will use this data to analyze the cost-effectiveness of utilizing ES for ancillary services as it installs and tests the 1 MW ES system at Harbor Substation.

Table 4: Recent Costs of Regulation Up

Regulation Up			
Year	MW	Amount	$/MW
2014	32,732	$211,308	$6.46
2015	33,092	$187,889	$5.68
2016	38,893	$427,961	$11.00

Table 5: Recent Costs of Regulation Down

Regulation Down			
Year	MW	Amount	$/MW
2014	31,309	$122,476	$3.91
2015	31,152	$97,224	$3.12
2016	39,319	$344,351	$8.76

Table 6: Recent Costs of Spinning

Spinning			
Year	MW	Amount	$/MW
2014	73,906	$366,017	$4.95
2015	38,723	$168,417	$4.35
2016	39,039	$236,031	$6.05

Table 7: Cost of Ancillary Services

Total Cost of Spinning, Non Spinning, Regulation Up, and Regulation Down			
Fiscal Year	Amount	Total Load (MWh)	$/MWh of Load
	Actual		
2014/2015	$579,174	2,500,131	$0.23
2015/2016	$982,240	2,500,977	$0.39
2016/2017	$940,007	2,427,397	$0.39
	Forecast		
2017/2018	$967,643	2,436,192	$0.40
2018/2019	$996,092	2,429,453	$0.41
2019/2020	$1,025,377	2,419,882	$0.42
2020/2021	$1,055,523	2,409,527	$0.44
2021/2022	$1,086,555	2,398,922	$0.45
2022/2023	$1,118,500	2,388,276	$0.47
2023/2024	$1,151,384	2,377,588	$0.48
2024/2025	$1,185,235	2,366,900	$0.50
2025/2026	$1,220,081	2,364,318	$0.52
2026/2027	$1,255,951	2,370,229	$0.53

Potential ES Technologies

To determine the appropriate technology for ES at the Canyon Power Plant, APU engaged Det Norske Veritas and Germanischer Lloyd (DNV GL) to review the current ES technologies and market trends. DNV GL is a company that provides advisory services in energy efficiency, renewable integration, clean conventional power generation, renewable plant operations improvement services, transmission and distribution grids, energy storage, measurements and cyber security.

This DNV GL study (Appendix B), completed in May 2017, is a joint effort with other member Publicly Owned Utilities from the Northern California Power Agency (NCPA) and the SCPPA. The study had two parallel tracks. In the first track, DNV GL reviewed seven current ES technologies in the areas of characteristics, capabilities, applications and cost-effectiveness. In the second track, DNV GL evaluated the process and rationale used by the CPUC for determining and adopting ES procurement targets and the related efforts by the three major IOUs (SCE, PG&E and SDG&E).

DNV GL reviewed and rated several current and commercially available ES technologies, and the detailed descriptions are in Appendix B:

- Lithium-Ion – utilizes the exchange of Lithium ions between electrodes to charge and discharge the battery; is well suited for fast-response applications like frequency regulation, frequency response, and short-term (30-minutes or less) spinning reserve applications; most popular chemistries are listed below.
  - Lithium Nickel Cobalt Manganese Oxide Battery (NCM)
  - Lithium Iron Phosphate Battery (LFP)
  - Lithium Titanate Battery (LTO)
- Vanadium Redox Flow Battery – also called Vanadium flow batteries; are based on the redox reaction between the two electrolytes in the system; can serve both long and short durations, but is more costly and still maturing.
- Flywheel Energy Storage – stores energy as the rotational kinetic energy of a spinning mass (the rotor); most useful and cost effective for very short duration plus high power applications.
- Compressed Air Energy Storage – stores electricity by compressing air into a reservoir and generates electricity by expanding the compressed air in a gas turbine; the compressed air is stored in a suitable geological formation such as salt domes, aquifers or depleted gas fields; is designed for to support extremely long duration energy applications.
- Thermal Energy Storage (ice-based technologies) – entails freezing water, or a water-based solution, at night to support space cooling during the day; application is exclusively space cooling and the associated load shifting.

Out of the ES technologies reviewed, DNV GL rated Lithium-Ion family of batteries most well-rounded in terms of providing fast-response applications. Lithium-Ion technologies have reduced in price and improved in operation. The next highest rated ES technology is Vanadium Redox batteries (VRB). APU found VRB to be costly and physically space-consuming in its 2014 ES Plan, and these two findings continue to be supported by the DNV GL study.

DNV GL noted that TES, despite its application being limited to exclusively space cooling, is cost competitive for facilities or utilities who host facilities. As indicated in its 2014 ES Plan, APU has successfully used or assisted customers to use TES to shift demand to off-peak hours at several sites throughout the City of Anaheim. TES has recently become available to residential customers, and SCPPA has a contract with the manufacturer, Ice Energy, for a pilot project. While the technology has proven results from commercial and industrial customers in the past before the CAISO's "duck curve" became problematic, APU does not deem it beneficial for its residential customers at this time due to its physical equipment size as well as the diminishing effectiveness of TES, as described previously. APU continues to follow the technological advancement in TES and the evolution of on-peak and off-peak periods from CAISO's duck curve and may consider TES again if it becomes viable.

Although the associated costs are still relatively high ($325-$850 per kWh for equipment costs depending on battery chemistry type), at this time, Lithium-Ion batteries appear to be the best choice for ES technology at the Canyon Power Plant.

Potential ES Configurations

The ES system at the Canyon Power Plant could have two potential configurations: hybrid battery ES or stand-alone battery ES. APU is still evaluating these two configurations based on testing, case studies, and proposal evaluations.

Hybrid Battery ES

General Electric has recently developed a new technology of hybrid modification (LM6000 Hybrid Enhanced Gas Turbine System or EGT™[10]) that adds battery storage to suitable power plants to provide additional spinning, regulation-up, and regulation-down reserves in addition to the previously capable non-spinning capacity. This technology combines a combustion gas turbine with an integrated battery storage component operated by a proprietary software system. With a hybrid battery configuration, APU could offer, or self-provide, spinning and non-spinning reserves into the CAISO wholesale market. These products reserve capacity that can be dispatched to ensure that the regional electric grid has sufficient electricity to serve load.

The Canyon Power Plant is a 200 MW plant consisting of four General Electric LM6000 combustion turbines, which regularly provide flexible ramping capacity to the CAISO. The Canyon Power Plant is potentially suitable for the abovementioned hybrid modification of 10 MW battery storage system. APU is closely following the application of this new technology as they are deployed in southern California.

The first project is the Stanton Energy Reliability Center project, developed by Wellhead Electric Company and awaiting CEC approval. This project, a proposed 98 MW facility in Orange County, California, utilizing the abovementioned technology, will provide generation for local reliability in SCE's West Los Angeles Basin Subarea.[11] Project construction is anticipated to begin late 2018 with full-scale commercial operation in 2019.

The second project is SCE's Center Power Plant in Norwalk, California. The Center Power Plant is a 50MW General Electric LM6000 combustion turbine that was modified to integrate a battery storage system from GE as a storage solution to SCE's 2016 Aliso

[10] General Electric, *Power Generation, Gas Turbine Upgrades, LM6000 Hybrid EGT™*, website, https://powergen.gepower.com/services/upgrade-and-life-extension/gas-turbine-upgrades/gas-turbine-upgrades-catalog/hybrid-egt.html, April 12, 2017.

[11] California Energy Commission, *Stanton Reliability Energy Center*, website, http://www.energy.ca.gov/sitingcases/stanton, April 10, 2017.

Canyon Energy Storage Request for Offers.[12] In April 2017, APU staff toured the Center Power Plant and its new 10 MW/4.3 MWh Lithium-Ion battery storage system to learn about the upgraded hybrid battery/turbine controls and the emission control system.

Stand-Alone Battery ES

The other potential ES configuration is the more common, containerized and stand-alone battery ES. To understand the current commercially available products, APU reviewed the responses to the Request for Information (RFI) on Energy Storage Technologies, issued by SCPPA on behalf of its member utilities on February 23, 2017 (see Appendix C). The RFI had a total of 14 responses, varying in ES technologies and proposals. Out of the 14 responses, APU found seven responses to be potentially suitable. These seven responses are battery storage technologies, including Lithium-Ion, Sodium Sulfur, and Vanadium Redox at various MW and duration capabilities, and their physical footprints may be appropriate for the reserved ES space in the planned Harbor Substation. APU in currently reviewing these seven responses and qualifications more in detail to determine the next steps for the pilot project.

Harbor Substation ES Pilot Project

In order to test APU's assumptions on installing ES at the Canyon Power Plant and gain first-hand experience on operating a battery ES system, APU has a pilot proposal to install a small 1MW ES system at the planned Harbor Substation in 2019. The Harbor Substation provides much needed operational flexibility, and will primarily serve the Platinum Triangle, a new development area in the City of Anaheim for residential, retail, restaurant, and office developments. Once complete, the substation will provide enough additional capacity to serve 15,000 customers. The electrical plot plan of Harbor Substation reserves a 30-by-50-foot space for ES. Based on the recent advancement in battery ES technologies, APU anticipates installing a 1 MW battery storage at the reserved space.

This pilot project will allow APU to:

- Fully evaluate the cost-effectiveness and viability of ES for energy time-shift and the self-provision of ancillary services;
- Gain first-hand experience with the operating characteristics of the selected technology; and
- Evaluate the feasibility of expanded uses such as backup resource adequacy capacity.

APU's focus has been, and will continue to be, delivering high quality service at reasonable rates in order to benefit its customers. To the extent that ES can be integrated seamlessly in a viable and cost-effective manner, APU will look for those opportunities. The discussions above demonstrate APU's continued commitment toward responsible resource procurement, which provides benefits that can ultimately be conveyed to Anaheim customer-owners.

[12] Southern California Edison, *Battery Storage Fact Sheet*, website, http://newsroom.edison.com/internal_redirect/cms.ipressroom.com.s3.amazonaws.com/166/files/20171/BattStorFactSheet-R5_withTESLA.pdf, April 10, 2017.

Section 4: Other Energy Storage Considerations

As indicated in the 2014 ES Plan, the functions and services provided by ES technologies need to be considered on a case-by-case basis. Deployment of ES systems would be highly situational and need to be evaluated at the time that a project is needed and proposed. Specific requirements such as location, intended use, duration of charge and discharge, number of cycles, availability of the ES system, and secondary functions need to be carefully considered. In addition to planning for ES installation at the Canyon Power Plant and the ES pilot project at the Harbor Substation, APU is currently evaluating other potential ES projects.

Yorba Battery Storage Project

APU is exploring opportunities for collaboration with third parties in or adjacent to the Yorba substation in which APU could gain experience in the operation of a 2.5 MW to 3.75 MW Lithium-Ion battery system in the CAISO wholesale electricity market. The project would be capable of charging and discharging around-the-clock and can be controlled and monitored remotely as needed to offer a variety of services such as scheduled dispatch, voltage control, frequency response, and peak management. As a public agency, APU will likely need to develop the supporting rules to allow third parties to connect to Anaheim's local grid, or develop an agreement to enable third parties with equal, non-discriminatory access to install ES systems. In either case, APU will seek review and recommendation by the Anaheim Public Utilities Board prior to seeking approval from the Anaheim City Council.

San Vicente ES Facility

The San Vicente Energy Storage Facility[13] is a joint proposed project owned by the San Diego County Water Authority and City of San Diego. The plan is to construct a closed-loop pumped hydro storage project at San Vicente Reservoir in Lakeside, California with an estimated online date of 2025. The proposed 500MW and 8 hours of storage capacity can be utilized to arbitrage power supplies (for integrating large new supplies of wind and solar electricity) and offer ancillary services. The project owners have received a preliminary permit from the Federal Energy Regulatory Commission (FERC), and they have also filed a joint Preliminary Application Document and a Notice of Intent with FERC. These documents are indicative precursors to a formal FERC license application. APU is currently collaborating with other public utilities through SCPPA to assess how this project, as a large pumped hydro storage facility, may be useful to balance the growing renewable generation resources that are required to meet the state requirements.

[13] San Diego County Water Authority, *San Vicente Energy Storage Facility Study*, website, http://www.sdcwa.org/san-vicente-energy-storage-facility-study, April 12, 2017.

Hoover Pumped Storage Project

Hoover Dam is APU's large hydroelectric energy resource and contributes 40 MW (or 5%) to APU's power supply. The Hoover pumped storage project is a proposal to install pump/piping to transport water from Lake Mohave to a higher elevation at Lake Mead. The proposed projects leverage the existing generating facilities at Hoover Dam, which are used for power generation when the stored energy is needed. Currently the proposal is in its early conceptual stage, and the Los Angeles Department of Water and Power is leading the efforts related to project feasibility study and cost estimates. APU is collaborating with other public utilities through SCPPA to follow the development of this project.

Section 5: Findings and Conclusions

AB2514 requires APU to determine appropriate targets, if any, to procure viable and cost-effective energy storage. The bill also requires that on or before October 1, 2017, the governing boards of all POUs shall re-evaluate their determinations of ES procurement targets to be achieved by December 31, 2021.

APU has re-evaluated its transmission, distribution, and customer resources. APU also reviewed the current technological services, availability, and costs for ES systems. Based on the professional studies and project evaluations, APU found that:

1. **<u>The procurement target for December 31, 2021 is a 1 MW pilot project at Harbor Substation:</u>** APU is in the process of planning for a 1 MW ES pilot project at its new Harbor Substation, which is located in a strategic load center serving high density developments in the Platinum Triangle, which is generally bounded by the 5 and 57 freeways and includes the Angel Stadium and Honda Center venues. Harbor Substation is currently being designed, and will include provisions for a 1 MW ES pilot system that is fully dispatchable and integrated with APU's other power resources. The Harbor Substation installation will allow APU staff to gain first-hand experience and validate the conceptual assumptions for future ES deployments, whether through APU procurement or by private corporations interconnected to APU's local grid.

2. **<u>The next procurement target is a 10 MW ES installation at Canyon Power Plant by December 31, 2026</u>:** Canyon Power Plant (Canyon) is a 200 MW gas-fired peaking power plant that provides fast start-up to mitigate ramping when solar generation is typically coming off-line. Anaheim is currently evaluating the most appropriate application of ES at Canyon, which may be a stand-alone system, or coupled with existing generating facilities in a hybrid manner that combines the speed of batteries with the efficiency of gas turbines. As battery ES technologies continue to mature and gain higher market share, different applications and control systems will be implemented and tested in California, allowing Anaheim to apply the solution best suited to its resource needs. With Anaheim's own testing at Harbor Substation being completed, Anaheim expects to have more data and experience on how to optimize the operation of ES and demonstrate value to Anaheim customers prior to seeking Anaheim City Council approval on future procurements and California Energy Commission (CEC) authorization as the Canyon site is within CEC's jurisdiction. A unique aspect of the Canyon Power Plant is that the existing 9-acre parcel has available space that was initially intended for future expansion of thermal resources; however, with the proliferation of intermittent renewables, APU now anticipates utilizing the available space for ES technology.

3. **<u>ES may be an area of opportunity for APU:</u>** APU is committed to collaborating with the California Independent System Operator (CAISO), other State agencies, and utilities to preserve and improve the reliability of the electric grid system. APU is

also committed in its holistic view that the procurement of reliable renewable resources, in a balanced manner, will continue to help the CAISO mitigate the need for additional flexible ramping capacity, in response to the overabundance and variability of wind and solar generation on the grid today. Although there is no immediate need for distribution infrastructure services or upgrade deferrals because Anaheim is essentially built-out and has a robust undergrounding program, over the next decade, ES may become a prominent part of APU's resource assets. The prominence of ES systems in Anaheim will also be dependent on the proliferation of utility-scale renewables as well as customer-owned distributed energy resources such as behind-the-meter solar and fuel cell systems that may require realignment of rate recovery mechanisms for fixed costs, adjustment of Time-of-Use (TOU) rates, and implementation of new demand response programs.

4. **ES may be viable and cost-effective for the provision of ancillary services:** Based on APU's analyses, ES currently has a limited effect in its ability to shift energy from one time period to another in the CAISO wholesale electricity market. However, APU studied the potential for ES to provide ancillary services. The costs of regulation and spinning reserves in the CAISO market for APU have increased significantly from 2014 to 2016. Regulation-up and regulation-down services cost approximately twice as much from 2014 to 2016, and spinning reserve cost increased by more than 20%. Since ancillary services are much smaller in megawatt volume compared to energy products, current battery ES technologies, particularly the Lithium-Ion technology, may be a potentially viable and cost-effective means to self-provide ancillary services. The proposed 1 MW ES pilot project at Harbor Substation and continued monitoring of ancillary service costs will help determine the feasibility of these benefits for future ES projects, and whether or not market conditions dictate potential acceleration of upcoming projects.

5. **APU is also considering other ES project proposals:** APU is currently reviewing three additional ES project proposals, the Yorba Battery Storage Project, the San Vincente ES Facility, and the Hoover Pumped Storage Project. These project proposals are intrinsically different in ES technology, application, and ownership structures. The project proposals will be evaluated to determine potential benefits to Anaheim customers.

From the findings above, APU concludes and recommends the following:

1. Adoption of ES procurement targets for December 31, 2021 at 1 MW for the Harbor Substation ES pilot project to plan for the 10 MW ES installation at the Canyon Power Plant by December 31, 2026; and,

2. Additionally, APU will continue to evaluate ES proposals, including the Yorba Battery Storage Project, the San Vincente ES Facility, and the Hoover Pumped Storage Project; and,

3. APU will continue to evaluate ES technologies and opportunities by monitoring other utility projects and collaborating with various utility industry and public agency groups.

APU's focus has been, and will continue to be, delivering high quality service at reasonable rates in order to benefit its customers. To the extent that ES can be integrated seamlessly in a viable and cost-effective manner, APU will look for those opportunities. The discussions in this Updated Energy Storage System Plan demonstrate APU's continued commitment toward responsible resource procurement, which provides benefits beyond APU's distribution system.

As energy and environmental policies drive electric grid changes by bringing more intermittent renewable energy resources on line, the potential benefits of ES becomes more apparent. ES can offer potential solutions by enabling renewables integration, gird optimization, and GHG reduction. APU's ES procurement targets will help the CAISO and other State agencies address new operational challenges to ensure a reliable and efficient electric grid for the foreseeable future.

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Attachment A

ANAHEIM PUBLIC UTILITIES

DG EVALUATION PROJECT: SITE EVALUATION

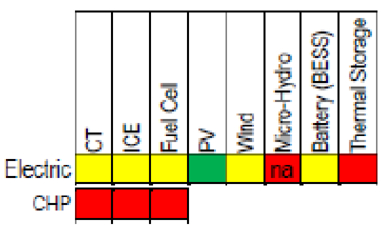
Site Name: Canyon Power Plant **Facility Type:** Power Plant
Address: 3071 East Miraloma Avenue

EXECUTIVE SUMMARY

The Canyon Power Plant is a 200 MW plant consisting of four LM6000 combustion turbines owned by the City of Anaheim. The 9 acre site is located on East Miraloma Avenue in an industrial area of the city with no residential areas nearby. Power generation at the site may be increased with a combined cycle expansion which was identified for possible completion in 2027 per Southern California Public Power Association's (SCPPA) project list. The results of each portion of the site evaluation for each technology are expressed visually below in accordance with the following key:

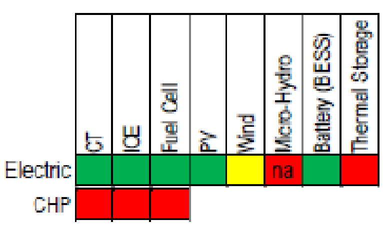
Feasible at This Site | Needs Further Evaluation | Not Feasible

Overall Evaluation



The site is a candidate for photovoltaic (PV) resources. Internal combustion engines (ICE), fuel cells, and combustion turbines (CTs) may not be desirable since those technologies would concentrate more thermal generation at the 200 MW plant. Wind is feasible but may face public opposition. Battery energy storage systems (BESS) may be feasible pending further study. Combined heat and power (CHP) applications are not likely due to low thermal loads and thermal energy storage (TES) is already in use and assumed to be optimized.

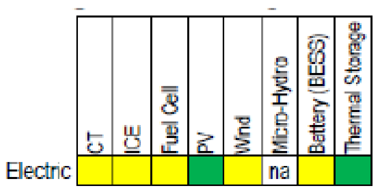
Site Characteristics



The 9 acre site is approximately 70% buildings, roads and structures surrounded by a 20 foot perimeter wall. Approximately 25% of the site is undeveloped and the remaining 5% is used for employee parking. Currently rooftop PV (98 kW) is installed on multiple buildings. The control room uses thermal energy storage to augment air conditioning. Approximately 100,000 ft2 of unimproved land is available for ground mount PV or other technologies including wind. Some parking is available for carport style PV installations. Thermal loads are likely too small for CHP. Thermal technologies will concentrate rather than distribute APU's power generation.

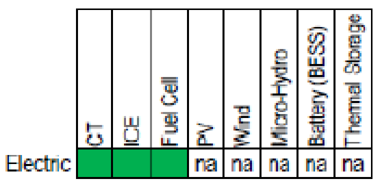
Site Name: Canyon Power Plant **Facility Type:** Power Plant
Address: 3071 East Miraloma Avenue

Zoning and Permitting



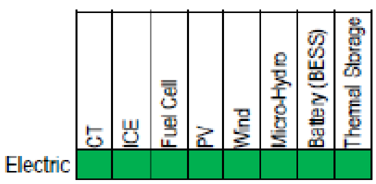
The site is part of the Anaheim Northeast Area Specific Plan (SP 94-1). The City owned property is not subject to the City's zoning requirements but the zoning height limit of 60 feet could increase public opposition to wind which would exceed height restrictions. Assume the 20 foot perimeter wall will provide sufficient sound attenuation for CTs, ICE, fuel cells and BESS although those technologies may see public opposition.

Fuel Infrastructure



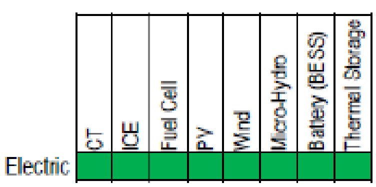
The site is in industrial area of Anaheim and the primary use of site is a natural gas fired power plant. Natural gas is available at the site in sufficient quantities for thermal generation alternatives.

Electric Infrastructure



The site interconnects with the 69kV APU distribution system via the switchyard located onsite. Current distribution system can handle additional Distributed Generation (DG) at the site without upgrades based on APU's simplifying assumptions.

Water Infrastructure



Based on current use at the site, incremental water for small CTs is available. All other candidate DG technologies operate as a closed loop system or require negligible quantities of process water.

Site Name: Canyon Power Plant
Address: 3071 East Miraloma Avenue
Facility Type: Power Plant

SITE CHARACTERISTICS

Site Location: 3071 E Miraloma Ave, Anaheim, CA.

The Canyon Power Plant is located in an industrial area of the city on E Miraloma Ave near N Kraemer Blvd. The site borders E Miraloma Ave and is surrounded on three sides by commercial and industrial businesses. The four combustion turbines, access roads and support structures occupy approximately 70% of the site. Undeveloped space is available on the east side of the site for a possible combined cycle expansion in 2027 (per SCPPA project list). The site has two small employee parking areas.

- 98 kW of rooftop PV is installed at the site.
- Thermal energy storage augments air conditioning in the control room.
- 25% of the site is unimproved.
- Entire site is surrounded by a 20 foot concrete block wall.

Current Site Use: Power Plant

Site Ownership: City of Anaheim

Lease/Operating Agreements: SCPPA Power Generation Project

Site Size:

	CT	ICE	Fuel Cell	PV	Wind	Micro-Hydro	Battery (BESS)	Thermal Storage
Electric						na		

Total Acreage: 9 acres

Buildings/Structures/Roads: 70%

Parking: 5%

Unimproved Land: 25%

Assessment: Usage is based on analysis of aerial imagery; sufficient space is available for all DG technologies considered.

Site Name: Canyon Power Plant
Address: 3071 East Miraloma Avenue
Facility Type: Power Plant

Site Availability

Rooftop for PV: 8,000 ft^2

Parking for PV: 4,000 ft^2

Land for Ground Mount PV and Other DG Technologies: 100,000 ft^2
(all estimated from aerial imagery analysis)

Parcels suitable for all DG technologies:

Parcel A (unimproved): 7,500 ft^2
Parcel B (unimproved): 25,000 ft^2
Parcel C (unimproved): 50,000 ft^2
Parcel D (unimproved): 16,000 ft^2
Parcel G (unimproved): 1,500 ft^2,
(30 ft. from S wall, possible shading)

Parcels suitable for PV carport-like structures:

Parcel E (surface parking): 2,000 ft^2
Parcel F (surface parking): 2,000 ft^2

Parcels suitable for rooftop PV:

Parcel H (switchyard): not suitable for PV

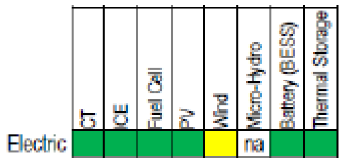
	CT	ICE	Fuel Cell	PV	Wind	Micro-Hydro	Battery (BESS)	Thermal Storage
Electric						na		

Assessment: Site is unsuitable for micro-hydro. Assume thermal energy storage is optimized by current installations. Estimated potential with no combined cycle expansion (estimates not based on specific unit size):

	Capacity (kW or MW)
CT: < 1,000 kW	150 MW
CT: 1,000 – 5,000 kW	
Recip.: < 3,000 kW	150 MW
Recip.: 3,000 – 10,000 kW	
Fuel Cell	50 MW
PV – Rooftop	0 kW
PV – Parking Structures	40 kW
PV– Ground Mount	750 kW
Wind	300 kW
Micro-Hydro	na
Battery (BESS)	100 MW (50 MWh)
Thermal Storage	0

Site Name: Canyon Power Plant
Address: 3071 East Miraloma Avenue
Facility Type: Power Plant

Adjacent Land Use



North: SoCal Gas, Butler Chemicals, Orange County Thermal Industries, Burnett Engraving.

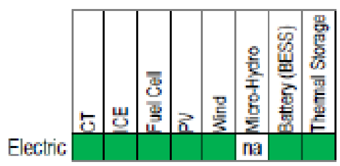
East: Kohn Megibow Co, Reel Lumber, Franciscos Meat.

South: E Miraloma Ave.

West: Westair Gases and Equipment, Time Warner Cable.

Assessment: Wind tower could cause interference with Time Warner communications tower to the west. Noise and aesthetic impact of other technologies likely to be less severe than existing power plant.

Topography

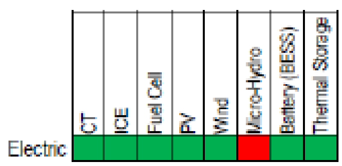


Elevation is 220 ft.

Site is essentially flat, no topological features of note.

Assessment: No topology issues.

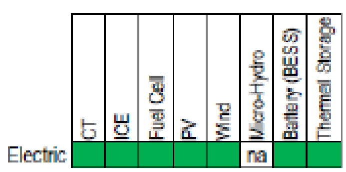
Hydrology



No rivers, streams, lakes or other watercourses on, adjacent to or in close proximity to the project site.

Assessment: No hydrology issues.

Natural Hazards



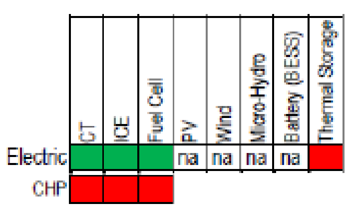
Flood Zone: X – 0.2% Annual Chance Flood Hazard.

No Special Hazard Area.

No dry water drainage paths through site.

Assessment: No natural hazard issues.

On-Site Thermal Loads



Annual load estimates are not available for the Canyon Power Plant.

Assessment: Assume existing thermal energy storage (TES) is optimized and other thermal loads are insufficient to support CHP applications.

ZONING AND PERMITTING

Land Use Considerations

	CT	ICE	Fuel Cell	PV	Wind	Micro-Hydro	Battery (BESS)	Thermal Storage
Electric						na		

Zoning: Northeast Area Specific Plan (SP 94-1, DA 1)

General Plan: Industrial

Assessment: City-owned sites are not subject to the City's zoning requirements per Anaheim Municipal Code (AMC) Section 18.90.030.040.

Land Restrictions

	CT	ICE	Fuel Cell	PV	Wind	Micro-Hydro	Battery (BESS)	Thermal Storage
Electric						na		

Maximum Permitted Structural Height Limit is 60 feet except as may be permitted by conditional use permit per Anaheim Municipal Code 18.120.050.

Assessment: City-owned sites are not subject to the City's zoning requirements but tall wind towers could increase public opposition. Small wind requires tower heights near 100 feet and 300 feet of clearance from surrounding obstacles. Wind may be feasible in unimproved area on west side of site.

Noise Restrictions

	CT	ICE	Fuel Cell	PV	Wind	Micro-Hydro	Battery (BESS)	Thermal Storage
Electric						na		

Anaheim Municipal Code 6.70.010 limits levels to 60 dBA at the property line.

Assessment: Assume 20 foot perimeter wall will provide sufficient sound attenuation for CT's (80 to 100 dBA), engines (60 to 80 dBA), fuel cells (47 to 72 dBA) and batteries (up to 80 dBA) to meet acceptable noise levels and mitigate public opposition.

Emissions Restrictions

	CT	ICE	Fuel Cell	PV	Wind	Micro-Hydro	Battery (BESS)	Thermal Storage
Electric				na	na	na	na	na

Based on the South Coast Air Quality Management District (SCAQMD): All internal combustion engines greater than 50 brake horsepower (bhp) and gas turbines greater than 2,975,000 British thermal units (Btu) per hour are required to obtain a permit to construct from the SCAQMD prior to installation of the engines at a site. New units must also meet New Source Review (NSR) requirements. Assume SB 1368 Emissions Performance Standards do not apply; candidate units are under 10 MW.

Assessment: New electric generation units will require permitting but new units are designed to meet NSR emissions standards and can be permitted.

Site Name: Canyon Power Plant
Address: 3071 East Miraloma Avenue

Facility Type: Power Plant

Protected Areas

	CT	ICE	Fuel Cell	PV	Wind	Micro-Hydro	Battery (BESS)	Thermal Storage
Electric						na		

No Natural Community Conservation Planning (NCCP) Area.

No known archeological sites or issues.

Assessment: Wind towers may increase bird mortality rates at the site.

Public Opposition

	CT	ICE	Fuel Cell	PV	Wind	Micro-Hydro	Battery (BESS)	Thermal Storage
Electric						na		

Based on response from APU, there has been a history of local opposition to development in the area.

Assessment: Assume PV is acceptable based on current installations at the site. Additional thermal generation, BESS and wind could cause issues from a public perception perspective.

FUEL INFRASTRUCTURE

Natural Gas Pipelines

	CT	ICE	Fuel Cell	PV	Wind	Micro-Hydro	Battery (BESS)	Thermal Storage
Electric				na	na	na	na	na

Site is in industrial area of Anaheim.

Primary use of site is a natural gas fired power plant.

Assessment: Natural gas is available at the site in sufficient quantities for thermal generation alternatives.

ELECTRIC INFRASTRUCTURE

Interconnection Points

	CT	ICE	Fuel Cell	PV	Wind	Micro-Hydro	Battery (BESS)	Thermal Storage
Electric								

Site interconnects with the APU distribution system via the switchyard located onsite at a voltage of 69kV (part of parcel H on the site map on page 3).

Assessment: Current distribution system can handle additional DG at the site without upgrades based on APU's simplifying assumptions. The APU Distribution Planning department can complete a detailed interconnection study during the DG implementation process if needed.

Site Name: Canyon Power Plant **Facility Type:** Power Plant
Address: 3071 East Miraloma Avenue

WATER INFRASTRUCTURE

Process Water

	CT	ICE	Fuel Cell	PV	Wind	Micro-Hydro	Battery (BESS)	Thermal Storage
Electric								

Assume capacity is available based on current use.

14" High-Density Polyethylene (HDPE) - E Miraloma Ave (recycled water)

14" Concrete Cylinder Pipe (CCP) – E Miraloma Ave

Assessment: 200 MW of combustion turbine capacity operate on site. Assume incremental water requirements for small CT are available. All other candidate DG technologies operate as a closed loop system or require negligible quantities of process water.

Industrial Wastewater

	CT	ICE	Fuel Cell	PV	Wind	Micro-Hydro	Battery (BESS)	Thermal Storage
Electric								

Assessment: No candidate DG technologies produce industrial wastewater requiring onsite treatment or trucking to offsite facility.

Wastewater

	CT	ICE	Fuel Cell	PV	Wind	Micro-Hydro	Battery (BESS)	Thermal Storage
Electric								

Assume capacity is available based on current use.

30" Vitrified Clay Pipe (VCP) – E Miraloma Ave

Assessment: CT discharge is 1,000 to 1,500 gallons per year and typically does not require treatment prior to disposal. All other candidate DG technologies produce negligible water discharge.

Site Name: Canyon Power Plant **Facility Type:** Power Plant
Address: 3071 East Miraloma Avenue

The Canyon Power Plant is a 200 MW plant consisting of four LM6000 combustion turbines owned by the City of Anaheim. The 9 acre site is located on East Miraloma Avenue in an industrial area of the city with no residential areas nearby. Power generation at the site may be increased with a combined cycle expansion which was identified for possible completion in 2027, per Southern California Public Power Association's (SCPPA) project list.

Leidos relied on a combination of the Canyon Power Plant Site Evaluation, DG Technology Characterization, and discussions with Anaheim Public Utilities (APU) to form the following recommendations:

- Photovoltaic (PV) and Battery Energy Storage System (BESS) facilities should be evaluated for planning level costs and benefits
- Combustion Turbine (CT), Internal Combustion Engine (ICE), Fuel Cell, Wind, Thermal Storage, and Combined Heat and Power (CHP) facilities are likely not desirable to APU at the Canyon Power Plant site, and should not be further evaluated

PV Facilities

The site is a viable candidate for limited PV resources. A challenge associated with developing a PV facility includes potential shading from the 20-foot perimeter wall surrounding the site. Parking areas may provide excellent PV opportunities, while the vacant land area may be better used for future baseload generation facilities rather than ground-mount PV.

Battery Storage Facilities

The site is a viable candidate for BESS facilities that have a relatively small footprint, the specifics of which depend highly on the contemplated technology and system design, and there is sufficient land area within the perimeter of the site. The perimeter wall would likely reduce the BESS noise below the Anaheim Municipal Code limits noise levels of 60 dBA at the property line.

CT, ICE, and Fuel Cell Facilities

The site is a viable candidate for additional CT facilities, as well as new ICE and Fuel Cell facilities, with sufficient space and electrical and natural gas infrastructure. However, Leidos does not recommend additional CT, ICE, or Fuel Cell facilities at the site for the following reasons:

1. APU has indicated that it would prefer not to concentrate additional DG at a central generation site, and
2. The site has been identified as a potential site for additional baseload generation.

Wind Facilities

The site is likely not a viable candidate for new DG wind facilities, for the following reasons:

1. APU has indicated that the necessary wind tower heights would likely generate significant local opposition, the lack of which was identified as a primary criteria for this evaluation, and
2. DG wind facilities require a threshold wind speed for economic viability, which is unlikely at this location due to generally low resource potential in the Anaheim area.

Thermal Storage Facilities

The site is likely not a viable candidate for new thermal storage facilities because the site already contains thermal storage facilities, which are already optimized for the size of the onsite load.

CHP

The site is likely not a viable candidate for new CHP facilities because it is unlikely that there is enough onsite thermal load to render a CHP application viable.

Site Name: Canyon Power Plant
Address: 3071 East Miraloma Avenue
Facility Type: Power Plant

Leidos has projected the costs and benefits associated with potential DG technologies which may be installed at the Canyon Power Plant. Leidos relied on a combination of the Canyon Power Plant Site Evaluation, DG Technology Characterization, the Initial Prioritization analyses, and discussions with Anaheim Public Utilities (APU) to form the following recommendations:

- Photovoltaic (PV) and Battery Energy Storage System (BESS) facilities should be evaluated for planning level costs and benefits and business case assessments.
- DG Combustion Turbine (CT), Internal Combustion Engine (ICE), Fuel Cell, Wind, Thermal Storage, and Combined Heat and Power (CHP) facilities are likely not desirable to APU at the Canyon Power Plant site, and should not be further evaluated.

The Canyon Power Plant was evaluated for specific parcels of available land or rooftop space which could be available for PV, and BESS facilities. Figure 1 below provides an aerial image of the Canyon Power Plant site, and a description of identified potential DG parcels follows.

Figure 1. Potential Canyon Power Plant DG Parcels

- Parcels suitable for all BESS technologies:

  Parcel A (unimproved): 7,500 ft^2
  Parcel B (unimproved): 25,000 ft^2
  Parcel C (unimproved): 50,000 ft^2
  Parcel D (unimproved): 16,000 ft^2

- Parcels suitable for PV carport-like structures:

  Parcel E (surface parking): 2,000 ft^2
  Parcel F (surface parking): 2,000 ft^2

- Parcels suitable for ground mounted PV:

  Parcel G (unimproved): 1,500 ft^2, (30 ft. from S wall, possible shading)

Ownership and Transactional Structures

Appendix A provides a discussion of various ownership and transactional structures related to DG.

DG Cost and Benefits Methodology

Each candidate DG resource was evaluated for its projected costs and benefits should it be installed at the Canyon Power Plant site. Each candidate resource was evaluated as if it were the only DG resource installed at the Canyon Power Plant (including multiple PV resource parcels), and at the estimated maximum generating capacities for each parcel as determined by Leidos and APU. For example, the PV analysis assumed that all available parcels were allocated to PV and only PV. The BESS analysis assumed that parcels A-D were allocated to BESS, and only to BESS.

The installed capital costs for each candidate resource were estimated using Leidos' internal estimates. Operating costs, including fixed and variable Operations and Maintenance (O&M) costs, as well as any applicable fuel or charging costs, were estimated using Leidos' internal estimates and combined with each resource's projected operating profile.

Each candidate DG resource's operating profile was projected using Leidos' proprietary production cost model, which simulated the likely dispatch of the candidate resource. For PV resources, the production profile was assumed to be fixed according to the projected solar irradiance at the Canyon Power Plant, less a 0.75% annual degradation factor which applies to each hour of the year.

The benefits for each candidate resource were estimated using projections of the market value associated with each resource's projected generation. The market values were projected using Leidos' projection of SP-15 zonal prices in the California Independent System Operator (CAISO) market. Additional benefits were calculated for avoided Transmission Access Charges (TAC) associated with each candidate resource's firm capacity rating. Per guidance from APU, there were no assumed benefits from avoided distribution system upgrades.

Site Name: Canyon Power Plant **Facility Type:** Power Plant
Address: 3071 East Miraloma Avenue

The Present Value of each candidate resource's annual net operating costs was calculated using an assumed 5% discount rate. All candidate DG resources are projected to have negative Net Present Values (NPV), indicating that their capital, debt service, and operating costs exceed their projected operating revenues. For PV resources, the NPVs were calculated using two methods: 1) assuming no monetization of the federal 30% Investment Tax Credit (ITC), and 2) assuming full monetization of the ITC. The resulting Net Present Values projected for each potential DG resource are provided in the table below:

Table 1. NPV[1] Projections by DG Resource

	PV	BESS
NPV ($2016 000)	(68)	(29,758)
NPV With ITC ($2016 000)	(25)	NA

1. NPVs calculated using 20-year term, assuming 5% debt service interest rate, 2.3% inflation rate, and discounted using assumed 5% Weighted Average Cost of Capital (WACC) rate

Details regarding each candidate resources' cost and benefits follow.

PV Facilities

The Canyon Power Plant site was evaluated for potential PV installations as described below. Each potential PV parcel identified in Figure 1 above was assumed to be maximized with a projected Canyon Power Plant total PV capacity of 55 kW-AC. Individual parcel capacities were used to project the hourly generation profile using an assumed 8760 hourly shape of solar irradiance at the Canyon Power Plant site.

The assumed capital and operating costs are provided in Table 2 below.

Table 2. PV Capital and Operating Cost Assumptions

Parcel	Installed Capacity (kW_{-AC})	Installed Capital Cost (2016 $000)	2017 FOM ($000)[1]
E	20	51	0.4
F	20	51	0.4
G	15	38	0.3
Total	**55**	**141**	**1.1**

1. FOM assumed to escalate annually at 2.3%.

Site Name: Canyon Power Plant **Facility Type:** Power Plant
Address: 3071 East Miraloma Avenue

Annual operating projections for total PV capacity, inclusive of all parcels, are provided in Table 3 below. Individual parcel operating results are included in Appendix B.

Table 3. Annual Cost / Benefit: PV Summary, Total for Parcels E-G

					Costs				
Year	Energy (MWh)	Market Energy Price ($/MWh)	Market Energy Revenue ($000)	Avoided TAC ($000)	FOM[1] ($000)	Debt Service[2] ($000)	Net Value ($000)	Monetized ITC Debt Service[2] ($000)	Monetized ITC Net Value ($000)
2017	104	31.61	3.3	1.2	(1.2)	(11.5)	(8.2)	(8.1)	(4.8)
2018	103	38.53	4.0	1.2	(1.2)	(11.5)	(7.5)	(8.1)	(4.0)
2019	102	45.45	4.7	1.3	(1.2)	(11.5)	(6.8)	(8.1)	(3.3)
2020	101	51.69	5.4	1.3	(1.2)	(11.5)	(6.1)	(8.1)	(2.6)
2021	101	54.20	5.6	1.4	(1.3)	(11.5)	(5.9)	(8.1)	(2.4)
2022	100	55.15	5.6	1.4	(1.3)	(11.5)	(5.8)	(8.1)	(2.3)
2023	99	57.00	5.8	1.4	(1.3)	(11.5)	(5.6)	(8.1)	(2.2)
2024	99	56.88	5.7	1.5	(1.3)	(11.5)	(5.7)	(8.1)	(2.2)
2025	97	56.53	5.6	1.5	(1.4)	(11.5)	(5.7)	(8.1)	(2.3)
2026	97	59.82	6.0	1.6	(1.4)	(11.5)	(5.4)	(8.1)	(1.9)
2027	96	60.55	5.9	1.6	(1.4)	(11.5)	(5.4)	(8.1)	(1.9)
2028	96	64.98	6.4	1.7	(1.5)	(11.5)	(5.0)	(8.1)	(1.5)
2029	95	66.86	6.5	1.8	(1.5)	(11.5)	(4.8)	(8.1)	(1.4)
2030	94	69.75	6.7	1.8	(1.5)	(11.5)	(4.6)	(8.1)	(1.2)
2031	93	74.93	7.1	1.9	(1.6)	(11.5)	(4.1)	(8.1)	(0.7)
2032	93	79.78	7.5	1.9	(1.6)	(11.5)	(3.7)	(8.1)	(0.2)
2033	92	83.35	7.7	2.0	(1.7)	(11.5)	(3.5)	(8.1)	(0.0)
2034	91	87.28	8.1	2.1	(1.7)	(11.5)	(3.1)	(8.1)	0.3
2035	91	92.94	8.5	2.1	(1.7)	(11.5)	(2.6)	(8.1)	0.8
2036	90	99.39	9.0	2.2	(1.8)	(11.5)	(2.1)	(8.1)	1.4
20-Year Net Present Value[2] ($2016)							**(68.4)**		**(25.3)**

1. FOM assumed to escalate annually at 2.3%
2. Interest rate on Debt Service and Discount Rate assumed to be 5%

BESS Facilities

The Canyon Power Plant was evaluated for a potential BESS installation in parcels A-D as shown in Figure 1 above; Leidos evaluated the full combined capacity of all four parcels as identified in Table 4 below and did not allocate specific BESS capacities to individual parcels. The BESS was evaluated for its ability to arbitrage between periods of low and high cost energy in the CAISO market.

The assumed capital and operating costs are provided in Table 4 below.

Table 4. BESS Capital and Operating Cost Assumptions

Parcels	Installed Capacity	Installed Capital Cost (2016 $000)	2017 FOM ($000)[1]
A-D	12,500 kW/50,000 kWh	38,363	543.5

1. FOM assumed to escalate annually at 2.3%.

Annual operating projections for the BESS facility are provided in Table 5 below. Due to the nature of BESS round-trip efficiency being less than 100%, avoided TAC for the BESS facility is negative, meaning the BESS facility is expected to increase TAC. Additionally, operating costs of a BESS facility did not include potential costs for augmentation of the battery system (if applicable), or costs incurred to address physical changes to the battery system occurring through cycling of the battery. Degradation of battery performance over time was also not modeled, and thus the data provided below serves only as a likely better case scenario for value given dispatching the battery system against forecast market prices, without controlling for the impact of cycling on battery performance or increased O&M costs to maintain the same level of performance.

Site Name: Canyon Power Plant **Facility Type:** Power Plant
Address: 3071 East Miraloma Avenue

Table 5. Annual Cost / Benefit: BESS Summary

Year	Discharge Energy (MWh)	Net Market Energy Revenue ($000)	Avoided TAC ($000)	Costs: Debt Service[1] ($000)	Costs: FOM[2] ($000)	Net Value ($000)
2017	21,538	484	(83)	(3,149)	(556)	(3,304)
2018	21,534	573	(86)	(3,149)	(569)	(3,231)
2019	21,459	663	(89)	(3,149)	(582)	(3,157)
2020	21,616	821	(94)	(3,149)	(595)	(3,017)
2021	22,022	953	(99)	(3,149)	(609)	(2,904)
2022	22,219	1,120	(104)	(3,149)	(623)	(2,756)
2023	22,616	1,215	(110)	(3,149)	(637)	(2,682)
2024	23,016	1,395	(117)	(3,149)	(652)	(2,523)
2025	23,163	1,532	(122)	(3,149)	(667)	(2,406)
2026	23,847	1,808	(131)	(3,149)	(682)	(2,154)
2027	23,797	1,943	(136)	(3,149)	(698)	(2,040)
2028	24,206	2,141	(144)	(3,149)	(714)	(1,866)
2029	24,203	2,429	(149)	(3,149)	(730)	(1,600)
2030	24,750	2,498	(159)	(3,149)	(747)	(1,558)
2031	24,453	2,503	(163)	(3,149)	(764)	(1,574)
2032	24,669	2,650	(171)	(3,149)	(782)	(1,453)
2033	24,653	2,643	(178)	(3,149)	(800)	(1,484)
2034	24,453	2,644	(184)	(3,149)	(818)	(1,507)
2035	24,334	2,807	(190)	(3,149)	(837)	(1,370)
2036	24,284	2,751	(197)	(3,149)	(856)	(1,452)
20-Year Net Present Value ($2016)						**(29,758)**

1. Interest rate on Debt Service and Discount Rate are both 5%
2. FOM assumed to escalate annually at 2.3%

Appendix B: DNV GL Study

DNV·GL

EXECUTIVE SUMMARY

Public Utilities Code Section 2836(b) requires the governing board of each local publicly owned electric utility to determine appropriate targets for the utility to procure viable and cost-effective energy storage systems to be achieved by December 31, 2016, and December 31, 2020, on or before October 1, 2014. The statute also requires each governing board to reevaluate the determinations made pursuant to this subdivision not less than once every three years, with the first three- year period ending October 1, 2017. To this end, NCPA and SCPPA contracted DNV GL to support their members in re-evaluating energy storage targets, energy storage technologies, as well as cost-effectiveness methodologies that can be used to make storage procurement decisions. This report will focus mainly on describing energy storage cost-effectiveness methodologies.

Assessing the cost-effectiveness of storage presents a unique set of challenges. Energy storage is comprised of a group of technologies that vary in stages of development from traditional systems (eg. pumped hydro) to emerging technologies (eg. adiabatic compressed air). In addition, the performance characteristics of these technologies vary from power (short duration) to energy (long duration), and have extensive differences in sizes, configurations, efficiencies, as well as the number of discharge cycles specific technologies can perform. Finally, when sited at certain locations of the grid, the devices can often perform multiple functions to solve different problems. Each of these variations presents a unique set up challenges when assessing the technology. As utilities and government agencies continue to assess storage cost-effectiveness, the notion that simplified approaches to valuing storage are not adequate and in fact, may even lead to incorrect results.

In this report, DNV GL summarizes the cost-effectiveness methodologies and tools that are being used in the industry. While cost is relatively straightforward, benefits of storage is much harder to quantify due to the reasons above. It is important to caution that the cost-effectiveness analyses may be difficult (and expensive) to perform because they are specific to technology, location and applications. Instead of providing benefit values for each application in general, this report provides several examples of storage use cases to illustrate how storage benefits can be evaluated at the transmission, distribution and behind the meter locations.

These use cases indicate energy storage is cost-effective for a specific subset of assumptions for a range of benefits versus a range of costs. The range of benefits evaluated in these use cases include: market revenue potential, avoided distribution investment and customer bill savings. In each use case evaluated, the cost-effectiveness reaches a breakeven point when the benefits side of the equation being at the upper end of the assumed value range, and the storage cost side being at the lower end of the assumed cost range. While there are specific storage use cases that are cost-effective, one cannot generally conclude that storage is cost-effective for a specific application or for a specific technology at the current prices and benefits.

As part of this project to support POU's AB 2514 compliance, DNV GL includes three deliverables in the appendices.

- Appendix A: Technology specification. DNV GL reviewed seven utility-scale and behind the meter battery technologies: lithium ion (nickel manganese cobalt, Iron phosphate, titanate), vanadium flow batteries, flywheel, compressed air, and thermal energy storage. For each of these technologies, DNV GL provided a fact sheet to introduce the technology, a summary of its technical parameters, component costs, costs trends, as well as their suitability for various applications. The six technologies examined vary widely in technical parameters and costs. However, the general trend is that costs are coming down for all technologies, especially for lithium ion batteries. Different technologies are suitable for different applications. Lithium ion and flow batteries in generally are well-suited for all applications examined. Flywheels have very fast response times, high power ratings and show no degradation for cycling, therefore are most useful for power applications. Compressed air systems can support extremely long duration energy application, in some cases, over a day of continuous energy. For behind-the-meter applications, lithium ion batteries dominate the market to provide customer bill management. Thermal energy, such as ice bear, is a cost-effective solution for bill management when there is a high thermal load.

- Appendix B: AB 2514 target setting for IOUs. CPUC adopted an energy procurement target of 1,325 MW for the three Investor-Owned Utilities in California. In this memo, DNV GL describes the process and rationale used by the California Public Utilities Commission (CPUC) for determining and adopting energy storage procurement targets. Although the CPUC chose not to discuss the thought process that went into developing the targets, some of the major observations with respect to the targets include: (1) the cumulative target is approximately 2% of peak load projected for 2020, and the split targets between the IOUs followed roughly the ratios of projected peak demand of the utilities (2) The growth in targets from 200 MW to 1,325 MW over 4 biennial solicitation cycles amounted to about 35% growth per cycle (or about 15% compounded annual growth rate, compared to much higher growth rates already seen in the adoption of various renewable energy technologies). (3) The target at transmission level appeared to be slightly more than half of the total target, with the other half at the distribution level (divided between utility-side distribution and customer-side behind-the-meter). In addition, the memo provides an update on the progress achieved by the utilities relative to the CPUC procurement targets. All the IOUs are on track to meet their targets; in fact SCE and SDG&E have made rapid progress against their procurement targets (at 90% and 70% respectively) as of early 2017.

- Appendix C ES-Select Overview Presentation. ES-Select is a storage educational and screening tool developed for newcomers to the industry to help them understand the broad landscape of storage costs and benefits. Instead of requiring accurate inputs to provide accurate answers, it is designed to work with the uncertainties of storage and applications characteristics, costs, and benefits and provides answers in some reasonable "ranges." Since the input of the tool is provided in ranges under normal distribution, the output is provided in ranges and the probability distribution of occurrence. ES-Select is not an appropriate tool to use to make decisions about storage deployment under a specific situation, but is a useful screening tool to help understand the range of technologies and applications in general.

1 INTRODUCTION

In 2013, AB 2514 codified Public Utilities Code Section 2836(b) to require the governing board of each local publicly owned electric utility to determine appropriate targets, if any, for the utility to procure viable and cost-effective energy storage systems to be achieved by December 31, 2016, and December 31, 2020, on or before October 1, 2014. The statute also requires each governing board to reevaluate the determinations made pursuant to this subdivision not less than once every three years, with the first three- year period ending October 1, 2017. To this end, NCPA and SCPPA contracted with DNV GL to support their members in re-evaluating energy storage targets, energy storage technologies, as well as cost-effectiveness methodologies that can be used to make storage procurement decisions.

It is not unique for a statute to require utilities to procure emerging energy technologies as long as they are cost-effective. In 2006, SB 1 required utilities to procure cost-effective solar. Compared to storage, evaluating the costs and benefits of solar was more straightforward: there is a predominant technology, the generation profile is comparable, and the cost can simply be quantified and compared with each other based on a straightforward dollar per Watt metric. Unlike solar, assessing the cost-effectiveness of storage presents a unique set of challenges. Energy storage is comprised of a group of technologies that vary in stages of development: from traditional systems, such as pumped hydro that has been deployed for decades, to emerging systems such as adiabatic compressed air, to lithium ion batteries that has been expanding its portfolio of applications in recent years. In addition, the performance characteristics of these multiple technologies vary from power (short duration) to energy (long duration), and differ vastly in configurations, efficiencies, as well as the number of discharge cycles they can perform. Finally, when sited at certain locations of the grid, the devices can often perform multiple functions to solve different problems. Each of these variations presents a unique set up challenges when assessing the technology.

2 ENERGY STORAGE COST-EFFECTIVENESS METHODOLOGIES

At present, there are a wide range of tools and methodologies for evaluating the cost-effectiveness of energy storage. While costs estimates can be relatively straightforward, benefits are much harder to quantify. Performing a rigorous cost-effectiveness analysis depends on many factors, including technology, location, applications, market conditions, local grid conditions, and the available mix of other resources on the grid. On top of these factors, there are numerous tools and methods for evaluating storage benefits. For example, for frequency regulation application, analytical tools such as KERMIT[1], needs to simulate a 4-second change in frequency regulation setpoints to map the pathway (or mileage) of the storage cycles to calculate the performance payments. For capacity value, production cost modeling tools, such as PLEXOS[2] or PROMOD[3], need to simulate the entire market on an hourly basis for a given year to find out the value of storage capacity. When it comes to distribution applications, power flow models for distribution circuits would be needed to analyze steady state circuit performance parameters to test the efficacy of storage to mitigate loading and voltage impacts. Figure 1 shows the time fidelity required for various storage analyses and some of the available tools on the market.

[1] DNV KEMA Renewable Market Integration Tool
[2] PLEXOS® Integrated Energy Model (PLEXOS)
[3] ABB's electric market simulation tool

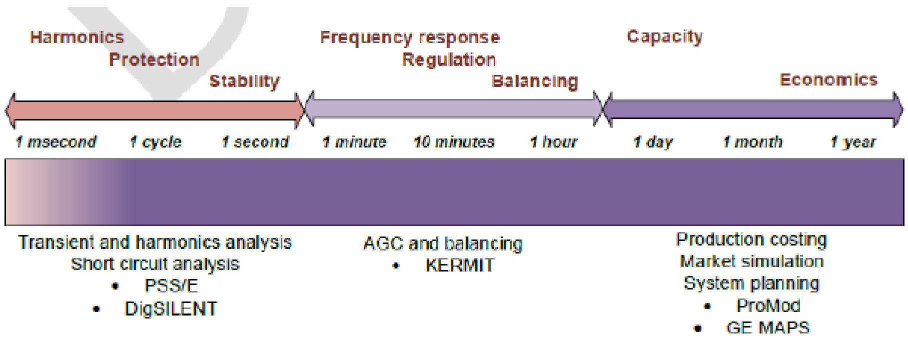


Figure 1 Time Fidelity Required for Storage Analysis and Current Tools

This document provides an overview of the prevailing cost-effectiveness methodologies currently being employed by the industry. A common challenge in developing comprehensive energy storage valuation methodologies is the relatively large number of potential storage applications. Each of these applications can take on varying magnitudes of value depending on the location of the storage device and corresponding system needs. Section 3 of this document contains a comprehensive definition list for each of the applications discussed in this report. Section 4 provides several case studies to illustrate how storage cost-effectiveness studies have been conducted and their associated results. To assist with describing these evaluation methodologies, DNV GL has segmented evaluation methodologies into three application areas: wholesale/transmission-connected, distribution-connected, and behind-the-meter.

2.1 Transmission-Connected Use Cases

For transmission-connected use cases, the benefits used in the cost-effectiveness modelling and evaluation include market revenues, i.e. market-based payments for the provision of Regulation Up (RegUp), Regulation Down (RegDown), Spinning Reserve (SR), Non Spinning Reserve (NSR) and other market services sold into the California Independent System Operator (CAISO) market, as well as local capacity payments from the utility to the storage owner, if any.

For market participation, energy storage valuation methodologies typically attempt to answer the following question: Given a storage device installed at a certain location that is eligible to participate in some number of CAISO markets/services, how should a storage device be operated such that its net benefit from market participation is maximized? For these market participation applications, the benefits are commonly considered only from the perspective of the device operator, and not from the perspective of the market or the utility. The bidding strategy and revenue potential are dependent only on the market prices available in the area in which the device is located. This is unlike a production costing dispatch approach, where devices are operated to minimize the cost to operate the market. Device-level benefits provide a starting point to derive its absolute worth to the utility / market. To derive the full benefits of a storage device to the utility, system level analysis and appropriate corrections are required. However, while evaluating the relative worth between two storage installations to the utility, device level benefits can provide a good indication of which one is better.

Some common assumptions on device level market participation include:

- Perfect Foresight: All inputs to the problem are exactly known before solving – e.g. prices, weather, renewable production, energy transactions while following ramping etc. This enables deterministic formulation, but this situation does not mimic real life. In reality, most inputs other than Day Ahead prices are not known exactly. The storage operator would devise a bidding strategy to maximize the probability of bids getting accepted and net expected benefits given uncertainty in inputs and errors in forecasted parameters.
- Price Taker: It is typically assumed that a storage device is relatively too small to impact the market clearing prices or affect the market price at a given node. The compensation to the device is the volume dispatched times the clearing price of energy or capacity.
- Zero Bid: Operator places $0 bid in capacity and/or energy markets based on perfect foresight dispatch computed. This implies that the bid is always accepted.
- Hourly Dispatch: Majority of tools do not resolve storage operation at time resolution finer than 1 hour. This primarily functions to reduce computation time, particularly when evaluating large number of scenarios. This assumption ignores the effect of convergence bidding or participation in real time energy imbalance services.

The analysis from the device perspective can typically be performed with spreadsheet modelling which can neglect system level constraints and coordinated operation of other devices in the system. When considering system level impacts, additional, more complex modelling tools are required.

Production cost simulation runs are typically used to determine the dispatch and relate hourly base clearing price for energy and ancillary service payments for a sample set of days that are then extrapolated for a representative year's 8760 market hours. Tools, such as DNV GL's KERMIT, can then be used for the inter-hour resolution needed to estimate the associated pay for performance benefit factors applied to the production simulation ancillary service base clearing prices. While there are other compensation schemes proposed and present within energy storage-based Power Purchase Agreement (PPA) term sheets today, there are not yet clear investment recovery mechanisms for these revenue streams. These potential additional services include: provision of volt-ampere reactive (VAR) to the local Participating Transmission Owner (PTO), blackstart capability, or fixed revenue streams via PPA with an LSE who wants to hedge market risk for their share of Ancillary Services costs.

When looking at the full system benefit, the benefit basis is the impact to system level metrics as solved in a production simulation. The modelled system benefits are estimated through comparing a portfolio without energy storage (usually known as base case) and a portfolio with energy storage included (change case). The primary system-level benefits include:

(1) Total cost of serving energy ($) and the average cost of energy ($/MWh)
(2) Total quantity of monitored emittants, including nitrogen oxide (NO_x) and carbon dioxide (CO_2)
(3) Number of conventional gas-fired unit starts which could be translated into starting costs and aggregated into total system costs

2.2 Distribution Grid Use Cases

The most frequently noted utility-side distribution connected storage applications are upgrade deferral, distribution operation support, and reliability. Of these applications, the most commonly cited cost-effective distribution application is upgrade deferral.

Upgrade Deferral

Distribution upgrade deferral involves using storage to delay or avoid utility investments that would otherwise be necessary to maintain adequate distribution infrastructure capacity to serve all load requirements. Upgrade deferral may include delaying the replacement of an over-stressed existing distribution transformer at a substation or avoiding the re-conductoring of distribution lines for higher load carrying capacity. When a transformer is replaced with a new, larger transformer, its size is selected to accommodate future load growth over the next 15-year to 20-year planning horizon. The upgrade of a transformer can be deferred by using a storage system to reduce the load on the transformer during peak periods, extending its operational life by several years.

To estimate the number of years of deferral that a given energy storage configuration can provide, a cost-effectiveness model will typically require historical SCADA load data as well as forecasted load growth for the feeder or substation transformer bank being considered. The primary benefits typically used in the cost-effectiveness modelling and evaluation are transmission and distribution (T&D) upgrade deferral (annual carrying charge for the upgrade deferral period) and T&D upgrade avoidance (first-year T&D installed cost avoided). There are several secondary benefits calculated in terms of system performance, but which are not carried forward as part of the financial benefits due to no existing clear means to monetize these system benefits. These secondary benefits ('with' versus 'without' energy storage performance benefits) calculated in the load flow solution include, energy (I^2R and I^2X) loss reduction, reduction in voltage regulation device switching, and reduction in the steady state voltage range.

Going forward, "bundled-use" of an energy storage device deployed for distribution deferral may be possible with appropriate regulatory rules in place. That is, the storage asset could offer multiple bundled applications such as wholesale market participation during time periods (which is typically most of the time) when it is not being used for deferral service (by offsetting peak load on the associated transformer or feeder circuit). In this case, valuation methodology would involve considerations similar to the ones discussed in the previous section on transmission-connected use cases.

Distribution operation (Voltage Support/VAR Support)

Utilities regulate voltage within specified ANSI standard limits by installing and operating tap changing transformers and voltage regulators at the distribution substation and by switching feeder capacitors downstream to follow load changes. This need is pronounced on long, radial lines with high loading or on feeders with high penetration of intermittent PV systems which may be causing unacceptable voltage deviations for neighboring customers. Placing distributed storage closer to affected infrastructure can improve network voltage profile, mitigate fluctuations, and reduce network power losses. [1]

Benefit of this application is typically attributed to avoided cost of additional voltage regulation equipment or system upgrades. In the case of avoided voltage regulation equipment as the only energy storage application, this benefit is typically nominal and not significant enough to justify energy storage at its current prices. However, if storage can avoid the need for extensive re-conductoring which would otherwise be required to correct a voltage deviation issue, the associated avoided cost benefit can make energy storage a cost-effective solution. While hourly resolution for the load flow simulations is typically adequate for assessing steady state voltage performance, the transient voltage concerns would require a higher time resolution and dynamic-capable electric system model to 1) capture the PV intermittency-related impact on transient voltages and 2) test the efficacy of a transient-response-speed capable energy storage system.

Outage Mitigation / Reliability

A storage system can effectively support customer loads when there is a total loss of power from the source utility. This support requires a storage system and customer loads to island during the utility outage and resynchronize with the utility when power is restored. The energy capacity of the storage system relative to the size of the load it is supplying determines the time duration that the storage can serve that load. This time can be extended by supplementing the storage system with on-site diesel gen-sets that can continue supporting the load for long-duration outages that are beyond the capacity of the storage system.[1]

It is however difficult to assess the value of reliability. The value of reliability can be quantified by the avoided cost of customers at risk of losing electricity service. This can be gauged from their willingness-to-pay for different types of interruption events at different time of day, day of week, season and geographical regions. These avoided costs can vary widely among different electricity customers. There have not been recent surveys that collect this type of data, so reliability values would be difficult to quantify. The most recent comprehensive study on reliability benefits were documented in an LBNL report in 2009 that uses data from 1989 to 2005[4].

2.3 Behind-the-meter Use Cases

2.3.1 Customer Bill Savings

The primary benefit for cost-effectiveness modelling and evaluation of behind-the-meter use cases is customer bill reduction through removal or reduction of demand charges applicable to some general commercial and industrial rate categories, and shifting PV output to reduce energy related charges. When installed alongside PV generation, energy storage capacity can be used to shift PV output to maximize coincident reduction in net load demand. Given that the benefits for this use case are strictly from the perspective of the retail customer, any incentives available to retail customers to encourage deployment of PV/storage systems also enter the benefits calculation as a reduction in capital expenditure (CAPEX) initial investment cost. Three common incentive programs for Californian customers include:

1. The California Self Generation Incentive Program (SGIP), applicable to energy storage
2. The California Solar Initiative (CSI), applicable to PV, for the Use Case sensitivities that include customer-sited PV
3. The Federal Investment Tax Credit (FITC), applicable to energy storage and PV, for the Use Case sensitivities that include customer-sited PV

[4] Michael J. Sullivan, Matthew Mercurio, Josh Schellenberg, "*Estimated Value of Service Reliability for Electric Utility Customers in the United States*," *LBNL*, June 2009

There are commercial tools available that can calculate customer bill savings, including DNV GL's Microgrid Optimization Tool and LBNL's DER-CAM. These tools typically calculate customer bill savings using the customer's load shape, electric tariffs, PV generation, and storage operation algorithm to calculate demand and energy charge savings.

2.3.2 Capacity Dispatch

Capacity dispatch is another commercially popular benefit category. The storage system could perform in utility or ISO capacity dispatch programs such as Demand Response, Local Capacity Resource (LCR), or Forward Capacity Market (FCM). Under these programs, the storage system would be notified ahead of time of the volume and duration of capacity required and the price of that service. Capacity dispatch may involve storage discharging (equivalent to load reduction) during peak or congested hours of the day such as early or late evening. Storage may also provide capacity service by charging (equivalent to load increase) to mitigate renewables over-generation. Such programs are being piloted in California.

Due to the deterministic nature of capacity dispatch scheduling, this application can be easily bundled with the Demand Charge Reduction (DCR) application. Storage control algorithm would need to co-optimize storage operation between these two applications to maximize revenue potential over the day. Commercial tools such as Microgrid Optimizer can model these bundled applications to demonstrate cost-effectiveness.

2.3.3 Other Customer benefits

In addition to customer bill savings and capacity dispatch revenue, storage can offer additional value in improving power quality and reliability. As noted above, these benefits are difficult to quantify and may vary widely depending on the individual customer's electrical needs.

2.4 Storage ES-Select

DNV GL acknowledges the difficulty for an industry newcomer to make decisions about storage given the complexity of the storage costs and benefits. To this end, DNV GL developed ES-Select for decision makers new to the industry to understand the broad landscape of storage. Instead of requiring accurate inputs to provide accurate answers, it is designed to work with the uncertainties of storage and applications characteristics, costs, and benefits and provides answers in some reasonable "ranges." ES-Select applies the Monte Carlo analysis to randomly choose hundreds of possible values within the provided ranges of input parameters, assuming a normal distribution. Consequently, the provided answers also have a range but the probability of occurrence of the answer within the provided range does not necessarily have a normal distribution.

To further educate and help decision makers on their options for energy storage or their applications and markets, ES-Select offers a wide variety of charts to compare the "ranges" of answers over a wide set of criteria, such as price and cost components, cycle life, size, efficiency, cash flow, payback, benefit range, and market potential.

The key characteristic that needs to be kept in mind when using ES-Select is that in developing this educational/consulting/screening tool, "simplicity" had far more priority than "accuracy." This decision support tool is made for the initial screening purpose when most facts are still unknown to the user, but some decisions still need to be made based on what is already known.

Another design principle in ES-Select is not to confuse the user by asking hard to answer questions upfront, but rather assume the most likely answers and allow the user to overwrite them if s/he has different answers. In other words, every question has a default answer that is often in the form of a range that would cover most, if not all, cases. The objective behind this design principle is to make the tool useful to both a beginner who needs to be educated on "reasonable" values as well as an experienced user who knows exactly what the problem is and has all of his or her numbers ready for input.

ES-Select was demonstrated to NCPA and SCPPA members in a workshop/webinar on November 2016. A public version of the tool can be downloaded from the US Department of Energy website[5]. The workshop presentation is available in Appendix A of this report.

3 STORAGE APPLICATIONS

A common challenge in developing comprehensive energy storage valuation methodologies is the relatively large number of potential storage applications. Each of these applications can take on varying magnitudes of value depending on the location of the storage device and corresponding system needs. In addition, some storage systems can perform multiple applications that can accrue a number of benefits. In this section, we provide a list of most commonly-cited energy storage applications, bundled applications, and the appropriateness NCPA's selected technologies for a particular application.

3.1 Application Definitions

The following list in Table 1 provides definitions, collated from number of public sources, for the most commonly cited energy storage applications, some of which were covered in more detail earlier in this memo:

Table 1: Energy Storage Application Segments

Wholesale/Transmission Connected	Distribution-Connected	Behind-the-meter

[5] http://www.sandia.gov/ess/tools/es-select-tool/

1. Provide frequency regulation services 2. Provide spin / non-spin reserves 3. Provide ramping 4. Provide Black Start 5. Avoid renewable curtailment and/or minimum load issues 6. Shift energy 7. Provide capacity 8. Smooth intermittent resource output 9. "Firm" renewable output 10. Improve transmission system operation (short duration performance, inertia, system reliability) 11. Avoid congestion fees	12. Defer system upgrades 13. Improve distribution system operation (Voltage Support/VAR Support) 14. Mitigate outages	15. Customer bill-management: Time-of-use (TOU) energy and demand charge management 16. Maintain power quality 17. Provide uninterruptible power supply

1. Provide frequency regulation services

Frequency regulation services available to storage include conventional regulation market products, fast regulation, as well as primary frequency response. Regulation involves managing interchange flows with other control areas to closely match scheduled interchange flows and momentary variations in supply or demand within the control area. The primary reason for including regulation in the power system is to maintain the grid frequency by reconciling momentary differences caused by fluctuations in generation and loads.

Typically, regulation is provided by generating units that are online and ready to increase or decrease power as needed. Their output is increased when there is a momentary shortfall of generation relative to demand and reduced when there is a momentary excess of generation.[1]

In most markets today, energy storage devices are now allowed to compete with generators in offering regulation services. Due to the fast ramp rate capability of most storage systems, a storage device can be quite valuable as a fast regulation device. In the fast regulation market, conventional plants such as gas turbine units would not be able to participate. CAISO controls the participating devices, which are dispatched according to optimal market operation.

2. Provide spin / non-spin reserves

Operation of an electric grid requires reserve capacity that can be called upon when some portion of the online supply resources become unavailable unexpectedly. Generally, reserves are sized to be at least as large as the single largest supply resource (e.g., the single largest generation unit) serving the system and reserve capacity is equivalent to 15% to 20% of the normal electric supply capacity. Spinning Reserve refers to generation capacity that is online (and synchronized to the grid system) but unloaded and that can respond within 10 minutes when needed to compensate for generation or transmission outages. Non-Spinning Reserve refers to generation capacity that may be offline or that comprises a block of curtailable and/or interruptible loads and that can be ramped to the required level (and synchronized to the grid system) within 10 minutes.[1]

3. Provide ramping

Conventional generation-based load following resources will increase output to follow demand up as system load increases and decreases output to follow demand down as system load decreases. Additionally, when renewables are present the demand on the conventional units to increase or decrease output increases with intermittency of the renewable supplies. In either case, the generator action to increase/decrease output is referred to as ramping. To enable ramping service, a generation unit must be operated at partial load, which is inefficient and requires more fuel per MWh, resulting in increased emissions per MWh relative to the generation unit operated at its design output level. Varying the output of generators will also increase fuel use and air emissions, as well as the need for more generator maintenance and thus higher variable operations and maintenance (O&M) costs. Storage is a well-suited alternative resource to provide ramping because it can operate at partial output levels with relatively modest performance penalties and respond very quickly when output modulation is needed for load following.[1]

4. Provide Black Start

Black Start is the procedure to recover from a shutdown of the bulk transmission system which has resulted in major loss of power supply. The black start process involves the starting of individual, isolated power stations (using on-site power that is not dependent on the bulk system to operate, such as a diesel genset) that can then serve to restore power to the ISO balancing authority area following a system outage.[2] A black-start unit provides energy to help other units restart and provide a reference frequency for synchronization. CAISO obtains black start services from generating units under interim black start agreements or reliability must-run contracts.

Energy storage systems can also provide an active reserve of power and energy within the grid and can be used to energize transmission and distribution lines, as well as provide station power to bring power plants on line after a large failure of the grid. Storage can provide startup power to larger power plants, if the storage system is suitably sited and there is a clear transmission path to the power plant from the storage system's location.[1]

5. Avoid energy curtailment and/or minimum load issues

Electricity generation and demand must be kept in balance at all times. When demand drops, it is necessary to ramp down and/or turn off generators. With higher penetration of variable renewable generation, there may be periods of excess generation (supply exceeds demand) which could lead to stability issues, overload, or over voltage constraints. Base-load units can only be ramped down to a minimum generation level in order to keep them online and avoid incurring an extended start-up time if forced to shut off completely. If an excess generation situation still persists after the ramp down of conventional units, it is then necessary to curtail non-firm renewable sources which may otherwise be producing power causing the excess supply condition. Energy storage can be employed as a sink to absorb excess generation during these low net-load (gross demand minus the renewable output) periods, storing energy which would otherwise be curtailed (wasted), and then supplying the energy back to the system during peak hours.

6. Shift energy

At the transmission and distribution level, electric energy time-shift involves purchasing inexpensive electric energy, available during periods when prices or system marginal costs are low, to charge the storage system so that the stored energy can be discharged or sold at a later time when the prices or costs are high. Alternatively, storage can provide similar time-shift service by storing excess energy production, which would otherwise be curtailed, from renewable sources such as wind PV[1] Operationally, this application is similar to avoiding curtailing excess energy as energy shifting on the transmission scale is performed during periods of over-generation.

7. Provide capacity

Capacity refers to the making power and energy available to given a electric market to serve current and future demand. Resource adequacy capacity requirements ensure sufficient resources are available in the CASIO market for safe and reliable operation of the grid in real time. Resource adequacy capacity is also designed to provide appropriate incentives for the siting and construction of new resources needed for reliability in the future. For a given capacity resource, the net qualifying capacity is the qualifying capacity of a resource adjusted, as applicable, based on: (1) testing and verification; (2) application of performance criteria; and (3) deliverability restrictions. Flexible capacity is defined as the quantity of resource capacity as specified by CAISO to meet maximum three hour ramping and contingency reserves. Depending on the circumstances in a given electric supply system, energy storage can be used as an alternative to buying new central station generation capacity and/or purchasing capacity in the wholesale electricity marketplace.

8. Smooth intermittent resource output

Smoothing intermittent resource output applies to circumstances involving renewable energy-fueled generation whose output change rapidly (over timescales ranging from seconds to minutes) due to transient cloud shadows on the PV array or short-term wind speed variability. With high renewable penetration, power output fluctuation may cause problems like voltage fluctuation and large frequency deviation in electric power system operation.[5]

Energy storage can be used to mitigate rapid output changes from renewable generation due to: a) wind speed variability affecting wind generation and b) shading of solar generation due to clouds. The resulting smooth renewable output offsets the need to purchase or rent highly dispatchable and fast-responding generation such as a simple cycle combustion turbine. Depending on location, smooth renewable energy output may also offset the need for transmission and/or distribution equipment.[4]

9. To "firm" renewable output

Firming is generally referred to renewable intermittency management over a longer time duration than smoothing. Renewables capacity firming applies to circumstances involving renewable energy-fueled generation whose output changes throughout the day due to change of solar insolation or wind speed.[4] The objective is to use additional dispatchable resources so that the combined output from renewable energy generation plus dispatchable resources is constant throughout the day.[4]

Storage can firm-up renewables output so that electric power can be used when needed, not just when the renewable resource is available.[3] The resulting firmed capacity offsets the need to purchase or rent additional dispatchable electric supply resources. Depending on location, firmed renewable energy output may also offset the need for transmission and/or distribution equipment.[4]

10. Improve transmission system operation (short duration performance, inertia, system reliability)

Energy storage used for transmission support improves the transmission system performance by rapidly compensating for real-time electrical anomalies and disturbances such as voltage sag, unstable voltage, and sub-synchronous resonance, resulting in a more stable system. Benefits from transmission support are situation- and location-specific. Transmission Stability Damping increases load-carrying capacity by improving dynamic stability. Sub-synchronous resonance damping increases line capacity by providing active real and/or reactive power modulation at sub-synchronous resonance modal frequencies. For transient power quality and stability applications, storage systems must be capable of sub-second response times.[1]

11. Avoid congestion fees

Transmission congestion occurs when available, least-cost energy cannot be delivered to all or some loads because transmission facilities are not adequate to deliver that energy. When transmission capacity additions do not keep pace with the growth in peak electric demand, the transmission system becomes congested. Thus during periods of peak demand, the need and cost for more transmission capacity increases along with transmission access charges. Locational pricing of electricity is employed as a tool to account for congestion when managing supply and demand of electric power in a specific area.[1]

Electricity storage can be used to avoid congestion-related costs and charges, particularly when the costs become prohibitive due to significant transmission system congestion. In this service, storage systems would be installed at locations that are electrically downstream from the congested portion of the transmission system. Energy would be stored when there is no transmission congestion, and it would be discharged (during peak demand periods) to reduce peak transmission capacity requirements.[1]

12. Defer system upgrades

Upgrade deferral refers to delaying, or avoiding, of a utility investments in required system upgrades, by using energy storage. Energy storage can enable upgrade deferral on the transmission or distribution network. For transmission, installing energy storage downstream from a nearly overloaded transmission node can defer the need for the upgrade by reducing the peak demand seen at the constrained location. A key consideration is that storage can be used to provide enough incremental capacity to defer the need for a large lump investment in transmission equipment. Doing so could reduce overall cost to ratepayers, improve utility asset utilization, allow use of the capital for other projects, and reduce the financial risk associated with lumpy investments. Additionally, the storage device is available to provide other applications when not reserved for deferral operations.[1]

Distribution upgrade deferral involves using storage to delay or avoid upgrade investments that would otherwise be necessary to maintain adequate distribution capacity to serve all load requirements. Upgrade deferral may include replacement of an aging or over-stressed existing distribution transformer at a substation or re-conductoring distribution lines with larger wire. When a transformer is replaced with a new, larger transformer, its size is selected to accommodate future load growth over the next 15-year to 20-year planning horizon. Thus a large portion of this investment is underutilized for most of the new equipment's life. The upgrade of the transformer can be deferred by using a storage system to offload it during peak periods, extending its operational life by several years. If the storage system is containerized, then it can be physically moved to other substations where it can continue to defer similar upgrade decision points and further maximize the return on its investment.[1]

13. Improve distribution system operation (Voltage Support/VAR Support)

Utilities regulate voltage within specified ANSI standard limits by installing and operating tap changing transformers and voltage regulators at the distribution substation and by switching feeder capacitors downstream to follow load changes. This need is pronounced on long, radial lines with high loading or on feeders with high penetration of intermittent residential PV systems which may be causing unacceptable voltage deviations for neighboring customers. Placing distributed storage closer to load can improve network voltage profile, mitigate fluctuations, and reduce network power losses. [1]

14. Mitigate outages

A storage system can effectively support customer loads when there is a total loss of power from the source utility. This system can be installed at the feeder level, such as community energy storage devices, or customer-sited behind the meter to pick up load when utility service is lost. This support requires the storage system and customer loads to island during the utility outage and resynchronize with the utility when power is restored. The energy capacity of the storage system relative to the size of the load it is supplying determines the time duration that the storage can serve that load. This time can be extended by supplementing the storage system with on-site diesel gen-sets that can continue supporting the load for long-duration outages that are beyond the capacity of the storage system.[1]

15. Customer bill management: Time-of-use (TOU) energy and demand charge management

At the customer-sited level, electric storage can be employed to reduce customer energy bills when operating under a time-of-use energy tariff. Customers can charge storage during off-peak time periods when the retail electric energy price is low, then discharge the energy during times when on-peak time of use (TOU) energy prices apply. This application is similar to electric energy time-shift, although electric energy prices are based on the customer's retail tariff, whereas at any given time the price for electric energy time-shift is the prevailing wholesale price.[1]

16. Maintain power quality

Energy storage can be applied to protect and compensate for on-site customer loads. Short-term power quality events such as voltage spikes, sags, surges, and frequency deviations, which can damage customer equipment, can be mitigated through proper operation of energy storage. Reactive power compensation can also be employed to improve customer power factor.

17. Provide uninterruptible power supply

Even momentary outages or power quality events can result in large-scale customer financial losses when sensitive electronic or process equipment loads are present. The electric supply to these pieces of equipment can be backed up to an uninterruptible power supply which can seamlessly switch from the utility power supply to energy storage backup when a power quality event or momentary outage occurs. For long-term outages, the UPS enables ride-through capability ensuring continuous supply of power to critical loads while other conventional back-up generation is brought on-line.

3.2 Shared Applications

One effective way to increase the value of an energy storage asset is to use it in multiple applications such that its capacity, power, or time could be "shared" among them in a coordinated, overlapping manner. If the shared capacities are not overlapping, such as dedicating certain percentages of the capacity to different functions (for example, 20% for back up and 80% for peak shaving), the total value is not necessarily increased and almost the same result can be obtained by buying two smaller storage units. Overlapping shared capacity, power, or time, is what can help stack up different benefits, but proper controls are required to assure the priority of access.

Some of the most common shared applications include:

- Customer bill management combined with capacity dispatch applications such as Demand Response
- Utility upgrade deferral combined with capacity dispatch applications or ISO services such as participation in wholesale markets

3.3 Application Ranking for NCPA's Selected Storage Technologies

DNV GL developed a ranking system for the various applications that battery energy storage systems may be utilized for within NCPA territory. Within this ranking system, information about each technology is used to ascertain its appropriateness for a particular application. The battery type's typical size and technical parameters influenced these rankings.

Each considered application was defined by its requirements for power, energy, cycling, and response time. These Application Requirements were scored on a comparative scale. For instance, in the case of the application of Electric Energy Time Shift, the energy capacity of the system is paramount and thus ranked highly. Alternatively, in the case of the application for Frequency Response, the energy capacity of the system is of lesser importance while response time and power capability are the prioritized requirements. Each technology was then defined by its capabilities to meet these requirements for power, energy, cycling, and response time. These technology capabilities were similarly scored on a comparative scale. For instance, Li-ion technology provides nearly instantaneous response time and was thus ranked highest in that parameter. Flow batteries, on the other hand, scored highest for cycling as they are capable of fully discharging daily with less impact on lifetime and degradation.

The Application Requirements and Technology Capability scores were then compared, defining how well-matched a specific technology was for a given application. For instance, if an application required fast response time, the technologies that provide a fast response time would score highest. Scores across each property were then averaged to provide a Technology Application score for each technology providing each application.

This assessment resulted in the application ranking show below, on a scale from 1 – 10, with 10 (indicated by dark green) demonstrating high correlation between application requirements and technology characteristics. Generally, DNV GL finds that a score of 6 or higher will allow a technology to sufficiently meet the requirements of an application. DNV GL's discussion and additional opinion around these results follows the table.

	Li-Ion NCM	Li-Ion LFP	Li-Ion LTO	VRB	Flywheel	CAES	TES
Electric Energy Time Shift	8	7	7	8	5	8	7
Electric Supply Capacity	8	7	8	8	5	8	6
Regulation	8	8	9	8	8	6	5
Spinning, Non-spin, Supplemental reserves	8	8	9	7	7	6	4
Voltage support / Power Quality	8	9	9	8	9	5	5
Load following / ramping support for renewables	8	8	9	8	7	6	5
Frequency response	8	9	10	7	9	5	4
Transmission and distribution congestion relief	8	7	8	8	6	8	6
Black Start	Y	Y	Y	Y	Y	Y	N
Reliablity	Y	Y	Y	Y	N	Y	N

	Li-Ion BTM
Bill management - DCM	9
Bill management - TOU	9
Bill management - Self-supply	9
Customer back up	8

Figure 2 Application Ranking of NCPA's Selected Storage Technologies

Under appropriate conditions, Li-Ion technologies are generally well-suited for all of the applications discussed. NCM and LTO specifically are highly rated across all applications reviewed here. LFP's lower cycle life and energy capacity reduces its ratings for repeated deep discharge usage, as seen in energy time shift and electric supply capacity. LTO, while being highly rated is, however, the most expensive of the three chemistries. As such, NCM is currently the most commonly implemented chemistry. Developments and research are, however, closing these gaps.

Similarly, VRB technology is well suited for all of the applications reviewed. While the system's ability to serve long duration makes it especially attractive for energy applications, VRBs can also support shorter, high power applications. Although the technology is less established than Li-ion, if the deployed systems prove performance to these operational characteristics and costs fall with further development, the technology will be attractive for long duration, utility-scale storage.

Flywheels have very fast response times, high power ratings, and show no degradation for high amounts of cycling. As such, this technology is most useful and cost effective for power applications. Although there are flywheel systems developed to serve for up to an hour at a lower power rating, most flywheels are designed for under a minute of use at a time at very high power. For this reason, energy applications all receive lower ratings in DNV GL's quantitative analysis.

In contrast, CAES systems are designed to support extremely long duration energy applications, in some cases, over a day of continuous energy. Due to this, DNV GL's quantitative assessment ranked CAES highly for the energy applications reviewed. CAES systems, purely based on their design mechanics, have a slow response time, requiring up to 10 minutes to respond to controls and serve the demand. As such, although CAES systems have large power values due to their scale, they are not well suited for applications that require quick responses such as voltage support, frequency response, or ramping for renewables.

Finally, ice energy storage is appropriate for energy time shift and reduction in peak demand due to space cooling. Further, when leveraged and coordinated in a single sub-load area, aggregated systems can provide both T&D congestion relief as well as be supportive for supply capacity application. Since peak cooling is highly seasonal and aligns with peak demand hours, wide-spread utilization of this technology can also help to delay infrastructure upgrades otherwise required to meet these concentrated peak periods.

4 STORAGE USE CASE STUDIES

It is difficult to determine cost-effectiveness for storage in general because determining benefits for storage often require modelling a specific technology at a specific location. The costs and benefits can vary depending on three main factors:

1. Location of the device on the grid. The device can be installed on the transmission grid, distribution grid or behind the meter. The benefits would vary based on the market prices or tariffs available at that location, as well as the condition of the grid at that location.
2. Storage technology. Storage technologies vary widely from duration, cycle times, efficiency, and physical configuration and constraints. In addition, different vendors offer the same storage technology in very different packages and functionalities. These factors affect the device cost, and the applications it can perform.
3. Applications. Storage technologies can perform 17 applications as outlined in Section 3. Most of these applications would require analysis using a modelling tool with proper time-scale and fidelity. For stacked applications, multiple analytical tools may be needed.

Providing a general value for storage will likely be wrong. Instead, the storage industry has opted to assess storage on an use case basis. The use cases would have defined assumptions such as location, technology, market, and tariffs. The most comprehensive energy storage cost-effectiveness use cases were completed under the CPUC storage proceeding by DNV GL and EPRI in 2013. Subsequently, new storage technologies have become available, storage costs have come down, renewables penetration has increased, and market conditions have changed. The 2013 results could be updated using the same cost-effectiveness methodologies; however, without additional analysis, it is safe to assume that the cost-effectiveness in general are more favorable now than in 2013.

The following sections provide examples of energy storage use cases in the transmission side, distribution side, and customer side level. The value basis for these findings are storage costs versus benefits, such as market revenue potential, avoided transmission and distribution (T&D) investment and customer bill savings versus storage cost. For each of the use cases, it shows that energy storage is cost effective for a specific subset of assumptions under a range of benefits versus a range of costs. The cost-effectiveness reaches a breakeven point when the value side of the equation being at the upper end of the assumed value range, and the storage cost being at the lower end of the assumed cost range.

4.1 Use Case #1: Transmission-connected storage to provide frequency regulation

Under CPUC's AB 2514 proceeding, DNV GL simulated the cost-effectiveness of a transmission-connected fast-responding providing frequency regulation under a performance payment regime. The frequency regulation market requires devices to match 4-second signals. The benefit of this use case is market revenue from CAISO. The case studies found that the breakeven point of the simulation is $882/kW

($3528/kWh) cost for the device. Any storage devices with costs below this level are even more cost competitive and any devices with costs higher are estimated to be not cost effective. Although this study is done for battery device, the operating characteristics are also representative of a flywheel, pumped hydro, or other fast acting storage device. The breakeven cost, that is benefit cost ratio (BCR) of 1, for a flywheel storage device is $6.44 million ($965/kW or $3,860/kWh). The study has assumed FR costs to increase 3% every year, but this has not been observed in the California Independent System Operator (CAISO) market. If regulation costs are twice what they were estimated to be, then the breakeven cost for a battery storage device participating in the CAISO regulation market is $40.78 million ($2,039/MW or $8,156/MWh).

The primary benefit used in the cost-effectiveness modeling and evaluation is market revenue. For the Frequency Regulation Only Use Case modeled, the form of market revenue quantified as a "benefit" is market-based payment for provision of Regulation Up (RegUp) and Regulation Down (RegDown) services sold into the CAISO market. The market pays devices in two ways: capacity payment for the opportunity cost of the committed capacity, and the performance of actual up and down movement of the resource following the signal (mileage).

DNV GL used high resolution production simulation modeling tool PLEXOS with DNV KEMA Renewable Market Integration Tool (KERMIT) tool to estimate the potential revenue stream in a future market scenario that includes Pay for Performance. Production simulation was used to determine the dispatch and related hourly base clearing price for RegUp and RegDown payments for a sample set of days that were then extrapolated for a representative year's 8760 market hours. The KERMIT tool was then used for the inter-hour resolution needed to estimate the associated Pay for Performance Benefit Factor applied to the Production Simulation (production cost based) RegUp and RegDown base clearing prices.

The benefit cost analysis is a pro-forma style analysis that estimates break-even capital costs for the 20 MW, 5 MWh storage device based on a 20 year revenue stream from CAISO regulation market and listed project financing assumptions. In addition, system benefits are estimated by determining the change in California production costs estimated by PLEXOS for the simulations with and without the storage device. Sensitivity analyses examining the influence of the primary factors are reported as well.

For the base case, the breakeven cost (a benefit-cost ratio of 1) for a 20 MW, 5MWh storage device participating in CAISO regulation markets from 2015 to 2035 is $17.6 million. This represents an $882/kW ($3528/kWh) cost for the device. Any storage devices with costs below this level are even more cost competitive and any devices with costs higher are estimated to be not cost effective. For example, a battery storage device with a capital cost of $600 per kW is estimated to have a 20 NPV of $7.50 million whereas a battery storage device with a capital cost of $1,000 per kW is estimated to have a 20 NPV of negative value of $3.14 million.

The breakeven cost, that is benefit cost ratio (BCR) of 1, for a flywheel storage device is $6.44 million ($965/kW or $3,860/kWh) and the BCR for a flywheel with a capital cost of $1,500 is 0.66. This is a 9.4% increase in breakeven capital cost compared to the battery storage device indicating higher capital cost projects are feasible. This is because the flywheel device has lower variable O&M costs and does not need to replace a battery stack every 10 years.

If regulation costs are twice what they were estimated to be, then the breakeven cost for a battery storage device participating in the CAISO regulation market is $40.78 million ($2,039/MW or $8,156/MWh). This is a

232% increase compared to the base case results. Using the capital costs CESA provides, the BCR for a battery is 2.18 and 1.33 for a flywheel.

From an operations point of view, the most important factor determining the breakeven cost is the performance of the storage device as that determines what fraction of the approximately $3 million the storage device is able to obtain. If the performance of the storage device is reduced by 10% (from 98% to 88% for up regulation performance and from 95% to 86% for down regulation performance) then the BCR decreases by 0.11 for a battery and 0.06 for a flywheel. The break-even cost decreases by 14%. The table below summarizes the simulation results of battery and flywheel under the base case and sensitivity cases.

Table 2 Summary Table of Benefits Costs for Scenarios for Regulation Markets

Scenario	Asset Type	Capex ($/kW)	Regulation Price Multiplier	Performance Multiplier	Benefit to Cost
Base Case	Battery	$750	1	1	1.09
	Flywheel	$1,500	1	1	0.66
2x Regulation Price	Battery	$750	2	1	2.18
	Flywheel	$1,500	2	1	1.33
P4P Performance Score (Pay for Performance)	Battery	$750	1	0.9	0.98
	Flywheel	$1,500	1	0.9	0.6

4.2 Distribution-Connected substation upgrade deferral

Substation upgrade deferral is the delayed investment of additional substation transformer capacity. Storage enables this deferral by reducing substation transformer peak loading during the hours of the years for which the respective equipment would have been overloaded without energy storage. In addition to peak shaving, the storage device can output reactive power to reduce voltage drops and losses across the substation transformer. Lastly, by reducing peak demand overloads on the substation transformed, the useful life of the substation transformer can be extended.

Distributed energy storage is typically not a cost-effective solution when a voltage deviation issue can be solved with traditional distribution voltage regulation equipment such as adding additional capacitors or voltage regulators. As shown in the case study done for the SDG&E (Section 4.2.1), relatively low cost of this traditional solutions as compared to utility scale energy storage at current prices made storage not a cost-effective solution. However, traditional voltage regulation solutions may not be viable or effective at addressing all voltage regulation issues, such as those arising in cases of high PV penetration on constrained feeders. In such cases, if circuit reconductoring is otherwise required, the associated avoided-cost benefit can make energy storage a cost-effective solution. An example of a cost-effectiveness analysis for distributed energy storage being employed to avoid circuit re-conductoring is shown in section 4.2.2.

4.2.1 Use Case #2: SDG&E distribution upgrade deferral

SDG&E contracted DNV GL to perform an independent cost-effectiveness analysis on the highest ranked bid from the 2014 Storage RFP. DNV GL applied its proprietary ES-GRID[6] modeling tool to assess the cost-

[6] The ES-GRID tool is an advanced modeling and simulation tool designed to assess the cost-effectiveness of energy storage connected on the distribution system. The tool is customized to a specific system and can assess the cost and benefits of single or bundled storage

effectiveness of the capacity upgrade deferral for each of the defined scenarios. DNV-GL simulated a total of 36 scenarios. As documented in details below, SDG&E found that 35 of 36 scenarios were not reasonably cost effective after applying both quantitative and qualitative evaluation criteria. The NPV savings of the lone cost effective scenario is $700,000. This NPV in savings is approximately 5% of the total installed cost for the highest ranked storage solution, and approximately 1% of the estimated substation costs, which includes a 30% contingency. This means the entire quantitative value of pursuing the storage solution rests on that solution's actual costs being almost exactly its estimated costs. If the actual costs exceed the estimated costs by 5% or more, the immediate value to customers is entirely eroded. However, if the substation's actual costs are only 1% less than estimated costs – not an implausible outcome give that the substation's estimated costs include a 30 % contingency – there is no immediate value to customers in having installed storage to defer construction of the planned substation. Given these objectively thin margins, SDG&E elected to not pursue the storage solution in this particular instance.

SDG&E identified a planned substation as a potential candidate for deferral by a cost-effective energy storage project. The planned substation is needed to accommodate expected growth of end-use load in one area of SDG&E's distribution service territory, maintain substation and circuit reliability, and reduce area substation loading to optimum operating conditions. The 2014 Storage RFP was designed to determine whether (i) an energy storage project could inject enough power, at the right times of the day and year and at the low voltage side of the existing transformers (where the distribution feeder circuits connect) to reduce power flows across the existing transformers to delay the point in time when the planned substation would need to be constructed, and (ii) the savings associated with deferring the construction of the planned substation would offset the cost of the energy storage project; i.e., would be cost-effective for SDG&E customers.

SDG&E worked with DNV GL to define a set of scenarios and inputs for the ES-GRID model runs. This scenario based approach allows for the cost-effectiveness of the energy storage project to be assessed over the range of bid pricing options, storage power and energy configurations, substation upgrade costs, and transformer bank overload triggers. To compute the number of years of deferral that each energy storage configuration can provide, the model used SDG&E's hourly SCADA load data and forecast load for each of the identified transformers. For each scenario, and across all 10 years of the simulation horizon, ESGRID computed the optimal hourly energy storage dispatch schedule for peak shaving on the impacted transformer bank. For each scenario, the ES-GRID analysis produces the hourly storage dispatch profiles, number of years of deferral, and days that storage would be dispatched for peak shaving. Using the computed deferral period, the model next calculated the net present value (NPV) based on various benefit and cost elements such as capital expenditure, installation cost, fixed and variable O&M costs, storage charging cost, deferral benefit, and deferred/avoided tax payments.

DNV-GL simulated a total of 36 scenarios and found that 35 of 36 scenarios were not reasonably cost effective after applying both quantitative and qualitative evaluation criteria. For the scenarios with 4 MW / 12 MWh storage solution and a 100% loading trigger, the model determined that 12 scenarios were cost effective (i.e., had a positive NPV), and concluded it is possible to defer the planned substation for three years, starting in 2018. For these scenarios, storage is dispatched in a limited number of hours on three

applications. Through scenario development, the tool allows for the direct comparison of multiple scenarios of a particular energy storage use case.

days in 2018, 2019, and 2020. However, at a closer look at these "cost-effective" scenarios, most of them require one or a combination of the following unrealistic characteristics:

- The planned substation cost to fall within the "high" cost category, or 20% over the engineering budget.
- The storage device contained warranty options that were significantly less than the asset's useful life

Only two scenarios were cost effective using the mid-case substation costs, and a 10-year warranty option. One scenario has an estimated NPV savings of $700,000, and another has an estimated NVP savings of $3,000 which is essentially a breakeven case. Removing the breakeven case, the only cost-effective scenario under reasonable assumptions has an NPV savings of $700,000. This amount is equivalent approximately 5% of the total installed cost for the highest ranked storage solution, and approximately 1% of the estimated substation costs, which includes a 30% contingency. To put this in perspective, the entire quantitative value of pursuing the storage solution rests on that solution's actual costs being almost exactly its estimated costs. If the actual costs exceed the estimated costs by 5% or more, the immediate value to customers is entirely eroded. Similarly, if the substation's actual costs are only 1% less than estimated costs – not an implausible outcome give that the substation's estimated costs include a 30 % contingency – there is no immediate value to customers in having installed storage to defer construction of the planned substation. Given these objectively thin margins, SDG&E elected to not pursue the storage solution in this particular instance.

4.2.2 Use Case #3: CPUC avoided distribution system upgrade for PV integration

For a different distribution-connected use case, storage is found cost-effective for PV integration when re-conductoring costs were high. Distribution upgrades avoidance, including re-conductoring and avoided regulator costs, accounted for the majority of the storage benefits. Distribution system loss savings were found to be only a small portion of the overall benefit. As shown in Figure 3, DNV GL ran 250 cases that were simulated for the distributed energy storage for PV integration Use Case. The break-even case reflects a correctly sized battery with high re-conductoring costs, low deferral value, and medium range storage costs. Sizing storage greater than the line limit needs increases costs with only small incremental benefit, resulting in non-economic cases. Additional benefits not valued here include improved power quality potential and potential improvements to system reliability.

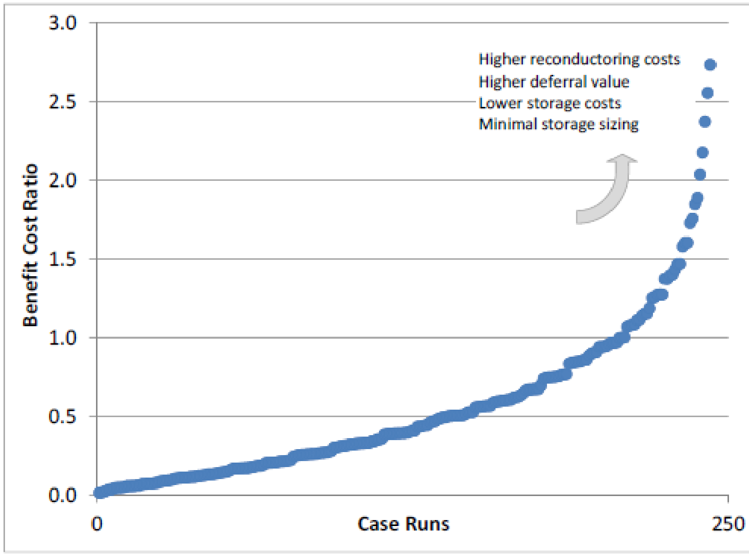


Figure 3 Benefits-Costs for Substation-sited Distributed Energy Storage for PV Integration

Energy storage can be employed by utilities to facilitate the integration of PV generation and mitigate possible negative impacts on the distribution system by:

1. avoiding system upgrades required for PV integration
2. mitigating voltage fluctuations at the primary distribution side resulting from intermittent distributed PV generation
3. reducing distribution system losses through improved utilization of distributed generation
4. deferring upgrade of substation equipment by time-shifting peak PV generation to coincide with system load peak

In the Use Case presented here, the avoided system upgrade is reflected as an avoided investment to re-conductor distribution equipment that would have become overloaded in the presence of reverse power flows from downstream PV generation. Energy storage is presented as an alternative to this equipment upgrade. The cost-effectiveness of energy storage for this Use Case is evaluated based on engineering modeling. In particular, the costs and benefits account for system-wide impacts, observed via time series power flow simulation. Also, the modeling results guide assumptions and evaluate the degree to which energy storage can meet the needs of the stated applications (at different energy storage sizes, for example). For this Use Case, the model simulates power flow over a sample multi-phase distribution test feeder, publicly available from the Institute of Electrical and Electronics Engineers (IEEE) as IEEE 123 Node

Test Feeder.[7] Simulation results for these systems are obtained using DNV GL's distribution energy storage valuation tool, ES-GRID.

Table 3 summarizes the engineering analysis results for IEEE 123 Node Feeder with PV generation. The results provided for the base case, represent the distribution system performance with PV and without energy storage. The columns to the right present distribution system performance with energy storage. Each column represents performance for the same distribution system, but with the corresponding size and duration of energy storage installed. The engineering analysis results illustrate the ability of energy storage to mitigate overloads of the capacity constrained lateral, eliminate both high and low voltage exceptions, reduce system losses, reduce system peak demand, and reduce voltage regulation tap changed operations.

Table 3: Summary Results for Distribution System Performance with PV and Energy Storage

Metric	Base case	500 kW, 2 HR	500 kW, 4 HR	1000kW, 2HR	1000kW, 4HR	2000kW, 2HR
Peak real power demand (kW)	4,369	4,341	4,341	4,259	4,259	4,145
Line capacity overload (Hours)	662	46	0	0	0	0
Maximum line flow (kW)	405	369	341	341	332	332
Total energy demand (MWh)	16,422	16,459	16,464	16,508	16,511	16,646
Total Losses (MWh)	605	581	568	572	568	622
Tap changes (#)	10,706	10,198	9,998	10,002	9,990	11,723
Maximum voltage (per unit voltage)	1.0568	1.0522	1.0490	1.0492	1.0473	1.0703
Overvoltage events (#)	123	11	0	0	0	356
Minimum voltage (per unit voltage)	0.94687	0.94699	0.94699	0.95178	0.95178	0.94431
Undervoltage events (#)	172	35	24	0	0	30

Drawing on the results of the engineering analysis, a cash flow analysis was run for a series of scenarios, using combinations of the key sensitivities: storage size, storage duration, storage costs, cost of re-conductoring, deferral value, and load growth rate. Six illustrative scenarios are shown in Table 4.

Table 4: Select Financial Results

Scenario #	Size	Deferral	Benefits	Costs	NPV	BCR
150	0.5 MW 4 hr	$309/kW	2,584	-2,392	192	1.1
177	1 MW 4 hr	$309/kW	2,867	-4,753	-1,887	0.6
138	0.5 MW 4 hr	$70/kW	2,399	-1,880	519	1.3
153	0.5 MW 4 hr	$538/kW	2,761	-2,392	369	1.2
147	0.5 MW 4 hr	$70/kW	2,399	-2,392	7	1.0

Figure 4 illustrates a cost-effective case, Scenario 150, on the left. The majority of the benefits are due to avoided re-conductoring upgrades. Additional benefit comes from substation upgrade deferral and some loss reduction. Larger energy storage investment, illustrated with Scenario 177, on the right, shows a slight

[7] "IEEE 123 Note test Feeder," IEEE Power Engineering Society, Power System Analysis, Computing and Economics Committee, Distribution System Analysis Subcommittee.

increase in value. However, the case is not cost-effective, as the incremental cost of sizing energy storage beyond the re-conductoring avoidance application is greater than the incremental benefits.

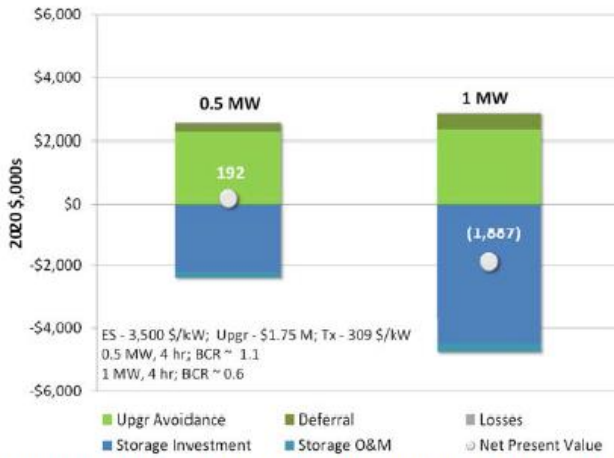


Figure 4: Cost, Benefits and NPV for Scenarios 150 and 177

Though re-conductoring is the primary benefit of this application, higher substation upgrade costs (and therefore higher deferral values) enable cost-effective cases with higher energy storage costs. Figure 5 illustrates two cases that are cost-effective, one with lower energy storage cost and deferral value (Scenario 138, on the left) and the other with higher energy storage cost and deferral value (Scenario 153, on the right).

Figure 5 Cost, Benefits and NPV for Scenarios 138 and 153

4.3 Use Case #4: Behind the Meter Storage for Bill Reduction

The primary use of behind the meter storage is for peak demand reduction. DNV GL modelled common area meter of multi-family residence and a school in SDG&E's territory. For the common area meter scenario, tariff switching gives an estimated Internal Rate of Return (IRR) of around 18%-27% depending on storage costs, while maintaining the facility on the same tariff gives an estimated IRR of around 9% -15%. For the school scenario, the best simulated IRR for a combined installation of solar PV and storage is around 17%-23%. The scenario with only storage installation in the school has an estimated IRR of 14%-38%.

Table 5: Financial Results for Different Customer Use Case Scenarios

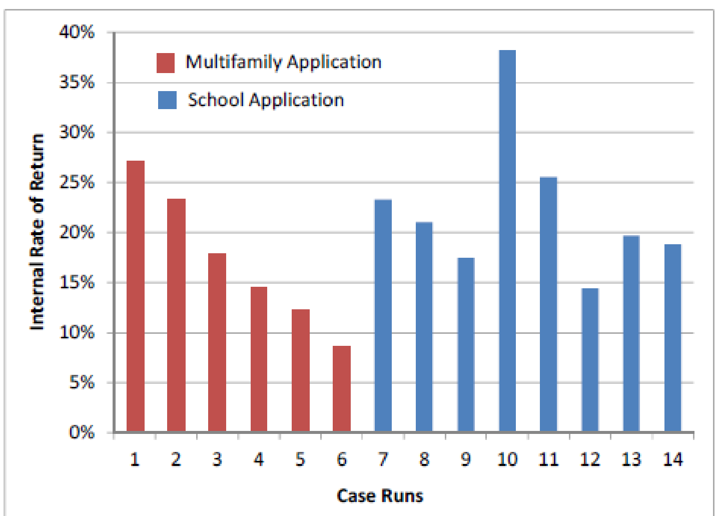
Storage cost ($/KW)	Installation			Incentives					Financial Results	
	Facility Peak	Installed Storage	Installed PV	SGIP	CSI	FITC PV	FITC Storage	Acc dep	IRR	NPV
Scenario 1: Storage and Solar PV dc-coupled Customer Type: Common area meter of multi-family residence Primary Function: Demand reduction to shift to different tariff										
Low - $3000/KW	21	5 KW, 10 KWhr	5 KW	YES	YES	YES	YES	YES	27.03%	$13,363
Med - $3500/KW									23.29%	$12,110
High - $4500/KW									17.90%	$9,602
Scenario 2: Storage and Solar PV dc-coupled Customer Type: Common area meter of multi-family residence Primary Function: Demand and energy charge reduction										
Low - $3000/KW	22.5	5 KW, 10 KWhr	5 KW	YES	YES	YES	YES	YES	14.55%	$4,692
Med - $3500/KW									12.17%	$3,438
High - $4500/KW									8.56%	$931
Scenario 3: Storage and Solar PV dc-coupled Customer Type: School Primary Function: Demand and energy charge reduction										
Low - $3000/KW	900	50 KW, 100 KWhr	50 KW	YES	YES	YES	YES	YES	23.26%	$164,918
Med - $3500/KW									21.02%	$152,382
High - $4500/KW									17.43%	$127,310
Scenario 4: Only Storage Customer Type: School Primary Function: Demand and energy charge reduction										
Low - $3000/KW	900	50 KW, 100 KWhr	50 KW	YES	NA	NA	No	YES	38.18%	$91,391
Med - $3500/KW									25.56%	$75,215
High - $4500/KW									14.41%	$42,864

For demand-side use cases the customer savings due to bill reduction required the ability to calculate the specific amount of demand reduced and energy shifted against a sample demand shape that has enough detail to adequately estimate the electric bill impacts. When other customer-side assets like PV are introduced, the control of energy storage within the model also required substantial controls logic (implemented via linear programing optimization) to answer the deceptively simple question - by how much can electric bill charges be reduced through a given storage system. DNV GL's Microgrid Optimization (MGO) tool was used to perform both the storage use optimization against an annualized demand shape to lower customer electric bill charges.

For the Demand Energy Storage category Use Cases, the primary benefit used in the cost-effectiveness modeling and evaluation is customer electric bill reduction through removal or reduction of Demand Charges applicable to some general commercial and industrial rate categories, and shifting PV output to reduce energy related bill charges. On-site PV was also included in several sensitivities which was added to the bill minimization optimization scheme by using available storage capacity to shift PV output for energy savings and account for any coincident reduction in net load demand. Given that the benefits for this Use Case are strictly from the perspective of the retail customer, retail customer incentives also enter into the 'benefits' calculation as a reduction in capital expenditure (CAPEX) initial investment cost.

Customer owned and operated storage is cost-effective for facilities with high peak demand to base load ratio, under tiered time-of-use (TOU) tariffs with high demand charges. In these cases, the current Self Generation Incentive Program (SGIP) incentives played a significant role in storage cost-effectiveness.

Figure 6: Internal Rate of Return for Multifamily and School Applications



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[2] Paul Denholm, Erik Ela, Brendan Kirby, and Michael Milligan, "*The Role of Energy Storage with Renewable Electricity Generation*," *Technical Report* NREL/TP-6A2-47187, January 2010

[3] EPRI-DOE *Handbook of Energy Storage for Transmission & Distribution Applications*, Final Report, December 2003

[4] Jim Eyer, Garth Corey, *Energy Storage for the Electricity Grid: Benefits and Market Potential Assessment Guide*, February 2010

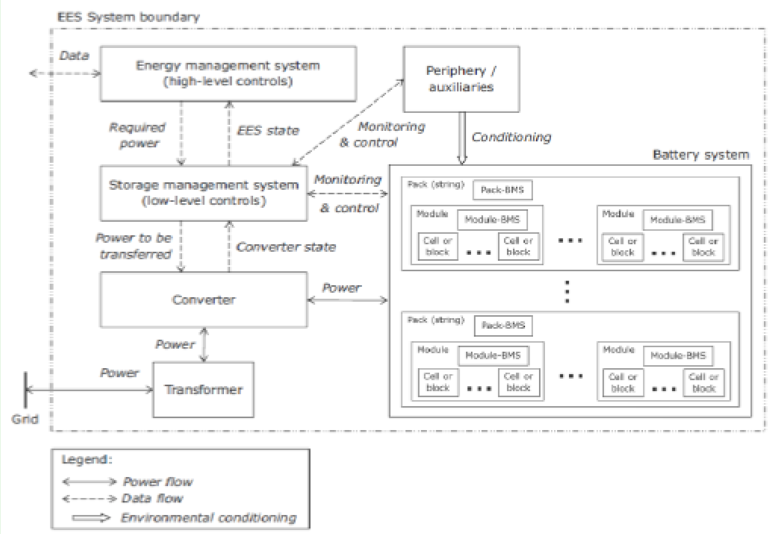
[5] T. Senjyu et al. *PV Output Power Fluctuations Smoothing and Optimum Capacity of Energy Storage System for PV Power Generator*

Lithium Ion

Lithium-Ion (Li-Ion) batteries utilize the exchange of Lithium ions between electrodes to charge and discharge the battery. Li-ion is a highly attractive material for batteries because it has high reduction potential, i.e., a tendency to acquire electrons (-3.04 Volt versus a standard hydrogen electrode), and it is lightweight. Li-Ion batteries are typically characterized as power devices capable of short durations (approximately 15 minutes to 1 hour) or stacked to form longer durations (but increasing costs). Rechargeable Li-ion batteries are commonly found in consumer electronic products, such as cell phones and laptops, and are the standard battery found in electric vehicles. In recent years this technology has developed and expanded its portfolio of applications considerably into utility-scale applications which, despite having very different requirements and features from consumer applications, benefit from the scale of manufacturing which lowers costs across markets. Because of its characteristics, Li-Ion technology is well suited for fast-response applications like frequency regulation, frequency response, and short-term (30-minutes or less) spinning reserve applications.

As with all energy storage technologies, Li-Ion batteries do carry some safety risk. Extreme over-heating or thermal runaway could cause fire and the release of toxic or reactive gases. This risk is strongly mitigated by various methods of cooling, including natural convection, forced air cooling, and liquid cooling, which keep the batteries not only at a safe temperature, but also at a temperature optimal for operation.

These risks are being regulated at an industry level, with the development, testing, and updates to safety standards, including recommendations for the appropriate response to fires. All Li-Ion systems being purchased and installed should be certified to such standards.



Parameter/ Technology		Li-Ion BTM		Li-Ion NCM	Li-Ion LFP	Li-Ion LTO
		Residential	C/I			
Power capacity	**Minimum**	2 kW	250 kW	1 MW	1 MW	1 MW
	Maximum	10 kW	1 MW	35 MW	35 MW	40 MW
Energy Capacity	**Minimum duration**	20 min	20 min	20 min	20 min	10 min
	Maximum duration	4 hr	4 hr	2 hr	2.5 hr	2 hr
Recharge rates		1C	1C	1C	2C-1C	3C-1C
Round trip efficiency		90%	82-83%	77 - 85%	78-83%	77-85%
Availability	**Up-time**	97%	97%	97%	97%	96%
	Carve Outs	72 hr/yr	72 hr/yr	72 hr/yr	72 hr/yr	72 hr/yr
Response time		ms	ms	ms	ms	ms
Degradation - Percent of initial capacity lost after 10 years	**Energy Applications**	40%	30%	30-40%	20-40%	15-25%
	Power Applications	10-20%	10-20%	10-20%	15-25%	5-15%
Expected life (100% DOD, 25*C, 1C)	**Years**	10	10	10	10	10
	Cycles	3,500	5,000	3,500	2,000	15,000

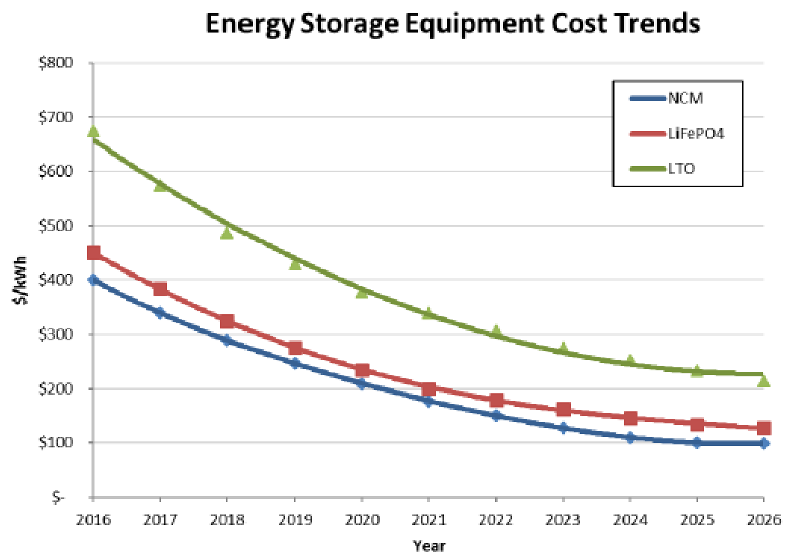
Lithium Ion

Lithium Ion energy storage systems, while differing across battery chemistries (as detailed later in this document), are generally appropriate for serving energy applications, moderate power applications, and applications requiring a short response time. Further, if charged at the time of the outage, Li-Ion systems can support a black start. Across the board, with an increase in adoption, Li-Ion technologies have reduced in price and improved in operation. However, of the technologies reported on in this project, Li-Ion batteries are some of the most sensitive to temperature. As such, Li-Ion systems are generally installed with cooling and heating systems, which may consume a portion of the useable system capacity.

Li-Ion is, in the current market, the dominating technology found in behind-the-meter (BTM) installations due in part to it's ability to scale to residential and commercial needs with a minimal physical footprint. BTM is used at the customer site to provide back up and bill management services. Bill management applications include electric time shift, to charge during lower time of use (TOU) periods and discharge during more expensive TOU periods; demand charge management (DCM), to discharge the battery in order to reduce peak load; and self-supply, to regulate the use of renewables thus more closely matching the renewable generation to the user load profile. Li-Ion technology is well suited for these applications due to its fast response time and recharge rate. Many systems are currently being designed with limited to no planned customer input or maintenance, but constant monitoring, controls, and service deployment as needed.

Utilities are beginning to investigate the aggregation of BTM storage to support grid services. The burgeoning demand for small scale distributed energy storage highlights the sometimes conflicting needs and requirements of utilities and end use customers, when high demand periods coincide. This poses an interesting controls and contracting challenge, but the flexibility of Li-Ion storage technology is appropriate for these broader and more intricate controls.

Based on DNV GL's quantitative assessment, under appropriate conditions, Li-Ion technologies are generally well-suited for all of the applications discussed. NCM and LTO specifically are highly rated across all applications reviewed here. LFP's lower cycle life and energy capacity reduces its ratings for repeated deep discharge usage, as seen in energy time shift and electric supply capacity. LTO, while being highly rated is, however, the most expensive of the three chemistries. As such, NCM is currently the most commonly implemented chemistry. Developments and research are, however, closing these gaps. The differences in chemistries are discussed further on the following page.



Cost Parameter/ Technology	Li-Ion NCM	Li-Ion LFP	Li-Ion LTO
Energy storage equipment cost ($/kWh)	$325-$450	$350-$525	$500-$850
Power conversion equipment cost ($/kW)	$350-$500	$350-$500	$350-$500
Power control system cost ($/kW)	$80-$120	$80-$120	$80-$120
Balance of system ($/kW)	$80-$100	$80-$100	$80-$100
Installation ($/kWh)	$120-$180	$120-$180	$120-$180
Fixed O&M cost ($/kW yr)	$6-$11	$6-$11	$6-$11
Major Maintenance ($/kW)	$150 - 400	$150 - 400	$150 - 400
Years between major maintenance	5	5	5

Li-Ion BTM	Residential	C/I
Total installed cost $/kWh	$530 - $765	$525-$700

Lithium Ion – Nickel Manganese Cobalt

$LiNiMnCoO_2$ (NCM or NMC) is one of the most commonly used chemistries in grid-scale energy systems. This technology demonstrates balanced performance characteristics in terms of energy, power, cycle life, and cost.

Nickel by itself has a high specific energy and poor stability whereas manganese offers low internal resistance with a low specific energy. Combining the two elements enables a high discharge current and leads to a better product. The cathode in this battery typically has a ratio of nickel to cobalt to manganese of 1-1-1 respectively but other combinations are also possible. The three active materials in NCM batteries can be easily blended and offer an economically viable solution for various applications. The NCM chemistry is most beneficial in applications where high battery cycle life, power and stability is required.

NCM batteries have a nominal charge of 4.10V/cell instead of 4.20V/cell, providing a lower energy capacity than Lithium Cobalt Oxide ($LiCoO_2$) batteries but higher energy density and longer life. NCM chemistry is very common due to these features as it provides an engineering compromise.

Lithium Ion – Iron Phosphate

$LiFePO_4$ (LFP) can be purchased at a low cost for a high power density, and its chemistry is considered one of the safest available within Li-ion batteries. Due to its very constant discharge voltage, the cell can deliver essentially full power to 100% DOD. However, $LiFePO_4$ batteries are typically applicable to a more limited set of applications due to its low energy capacity and elevated self-discharge levels.

LFP batteries offer low resistance, high current rating and long cycle life. They also perform well when kept at high voltages for a long time and have higher rates of discharge compared to other Li-ion batteries. The nominal voltage of a LFP cell is 3.20V and has a round-trip efficiency of 92%. Compared to other technologies, a LFP battery can still retain a 90% efficiency when discharge rates are low.

LFP batteries do not need to be fully charged which offers flexibility in installations where multiple cells are connected in parallel. In other words, battery operation is not compromised if multiple batteries in a system have different levels of charge. LFP battery chemistry is not prone to thermal runaway and thus reduces the risk of combustion. LFP batteries have low internal resistance, are more stable when overcharged and can tolerate higher temperatures without decomposing.

Lithium Ion – Titanate

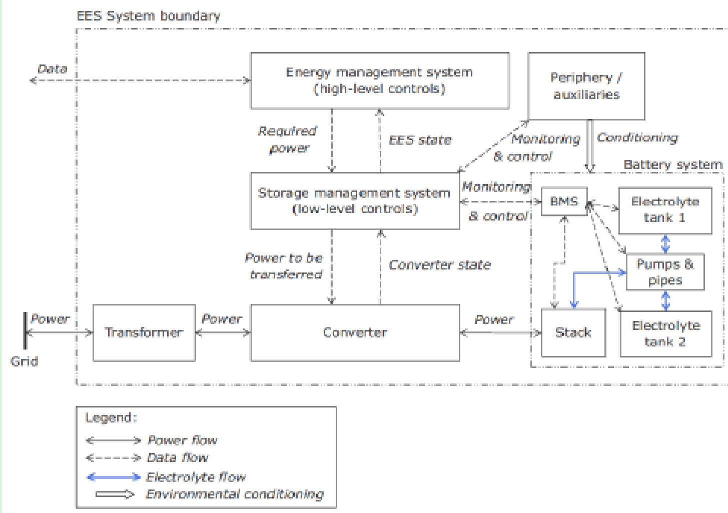
Lithium Titanate ($Li_4Ti_5O_{12}$ or LTO) offers a stable Li-ion chemistry, one of the highest cycle lifetimes reported for Li-Ion batteries, and a high power density. LTO battery cells take advantage of nanocrystals that allow the anode to have a larger surface area than other Li-ion battery technologies. The LTO nanocrystals result in an anode with a surface area of 100 m^2/gram, a large increase from traditional carbon or graphite materials with surface areas of 3 m^2/gram. This characteristic allows electrons in an LTO battery to enter and leave the anode quickly and provide a lifecycle that is upwards of 15,000 cycles.

The large anode surface area in LTO batteries also allows them to have a recharge efficiency of 98% which is relatively high. This enables LTO batteries to be charged quickly, requiring less electricity and power compared to other rechargeable batteries. The nanocrystals used in LTO batteries also allow better performance at low temperatures and can be beneficial to customers in areas with cold winters.

LTO cells have a nominal voltage of 2.40V allowing them to have a higher discharge rate than other Li-ion batteries. Their lower operating voltage also results in increased safety. Additionally, because LTO batteries do not use carbon, they do not overheat and significantly reduce any chance of fires. Their low operating voltage as well as cooler operating temperatures make them some of the safest rechargeable battery technologies in the market.

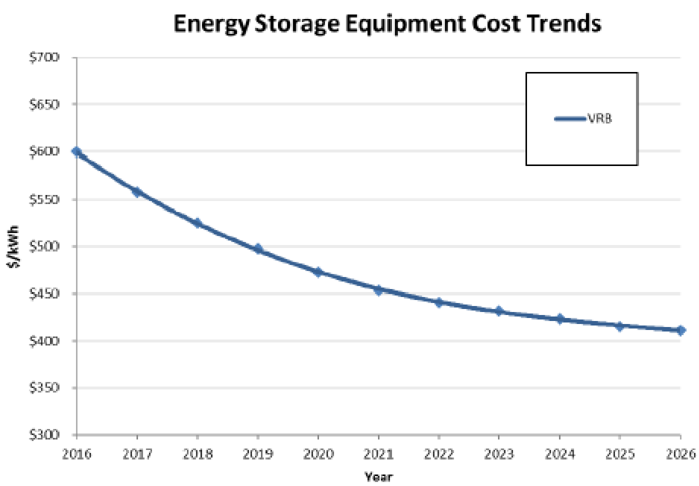
Vanadium Redox

Vanadium Redox batteries (VRB), or Vanadium flow batteries, are based on the redox reaction between the two electrolytes in the system. "Redox" is the abbreviation for "reduction-oxidation" reaction. These reactions include all chemical processes in which atoms have their oxidation number changed. In a redox flow cell, the two electrolytes are separated by a semi-permeable membrane. This membrane permits ion flow but prevents mixing of the liquids. Electrical contact is made through inert conductors in the liquids. As the ions flow across the membrane, an electrical current is induced in the conductors to charge the battery. This process is reversed during the discharge cycle. A general VRB system includes monitoring, control, and management systems, power converter/inverter, and the electrolyte tanks and stack of the batteries themselves. An important advantage of VRB technology is that it can be "stopped" without any concern about maintaining a minimum operating temperature or state of charge. This technology can be left uncharged essentially indefinitely without significant capacity degradation.



In VRBs, the liquid electrolyte used for charge-discharge reactions is stored externally and pumped through the cell. This allows the energy capacity of the battery to be increased at low cost. Energy and power are decoupled, since energy content depends on the amount of electrolyte stored. VRB systems are unique in that they use one common electrolyte, which provides opportunities for increased cycle life. These large, liquid solution containers do however limit the VRB to utility or large industrial installations.

Based on DNV GL's quantitative assessment, VRB technology is well suited for all of the applications reviewed. While the system's ability to serve long duration makes it especially attractive for energy applications, VRBs also support shorter, high power applications. VRB's chief limiting factor is cost, requiring more expensive equipment, installations, and maintenance. Additionally, the technology is less mature than Li-Ion systems, but is solidifying its place in the market. As such, the current claimed efficiencies, degradation rates, and expected life will continue to be updated with field data. If the deployed systems prove performance to these operational characteristics and costs fall with further development, the technology will be attractive for long duration, utility-scale storage.



Cost Parameter/ Technology	VRB
Energy storage equipment cost ($/kWh)	$500-$700
Power conversion equipment cost ($/kW)	$500-$750
Power control system cost ($/kW)	$100-$140
Balance of system ($/kW)	$100-$125
Installation ($/kWh)	$140-$200
Fixed O&M cost ($/kW yr)	$7-$12
Major Maintenance ($/kW)	$600 - $800
Years between major maintenance	8

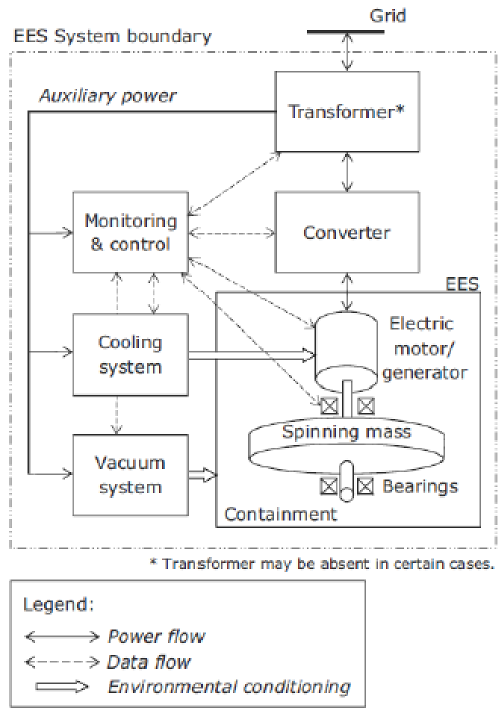
Flywheel Energy Storage

A flywheel stores energy as the rotational kinetic energy of a spinning mass, i.e. the rotor. The rotor is accelerated by an electric machine acting as a motor during charging, and decelerates when energy is extracted (discharging mode) by the same machine acting as a generator. To reduce friction losses during rotation, in general the rotor spins in a vacuum and magnetic bearings are used to keep the rotor in position.

The amount of energy that can be stored is proportional to the mass, the square of the rotational speed and the square of the radius of the rotor. Power rating is determined by the electric motor/generator. Flywheels require external power to maintain its rotational velocity. These idling losses incur a relatively high self-discharge rate. Self-discharge rate is mainly influenced by the bearing technology and the quality of the vacuum.

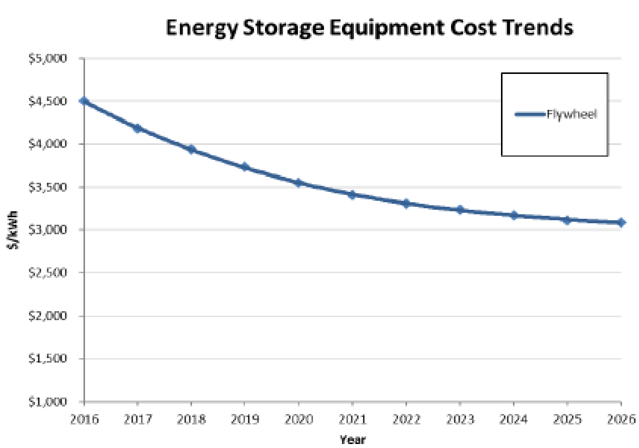
To stabilize the rotating mass bearings are needed. Modern flywheels often operate fully contact-free levitated by magnetic bearings or a combination of magnetic bearings and high speed roller bearings. Often the bearing system requires peripheral systems like an electronic controller for the active magnetic bearing system. The flywheel-mass rotates under low pressure (often vacuum or even high vacuum) in a containment to reduce friction losses. On the one hand the containment acts as the low pressure vessel, on the other hand it acts as a safety measure in case of a disintegration of the flywheel.

In a flywheel-based energy storage system, each flywheel has its own converter. Multiple converters may then be connected to one transformer.



Flywheels have very fast response times, high power ratings, and show no degradation for high amounts of cycling. As such, this technology is most useful and cost effective for power applications. Although there are flywheel systems developed to serve for up to an hour at a lower power rating, most flywheels are designed for under a minute of use at a time at very high power. For this reason, energy applications all receive low ratings in DNV GL's quantitative analysis.

Due to the short design duration of flywheel systems, the $/kWh values are much larger in comparison to other storage technology reviewed here. However this is not true of the total system costs, which trend closer to that of the other technologies. Flywheels do not require significant or expensive maintenance, which further positively affects their overall cost. However, systems do vary widely in cost and maintenance, depending on what materials are being used and which of the configurations discussed above are utilized.

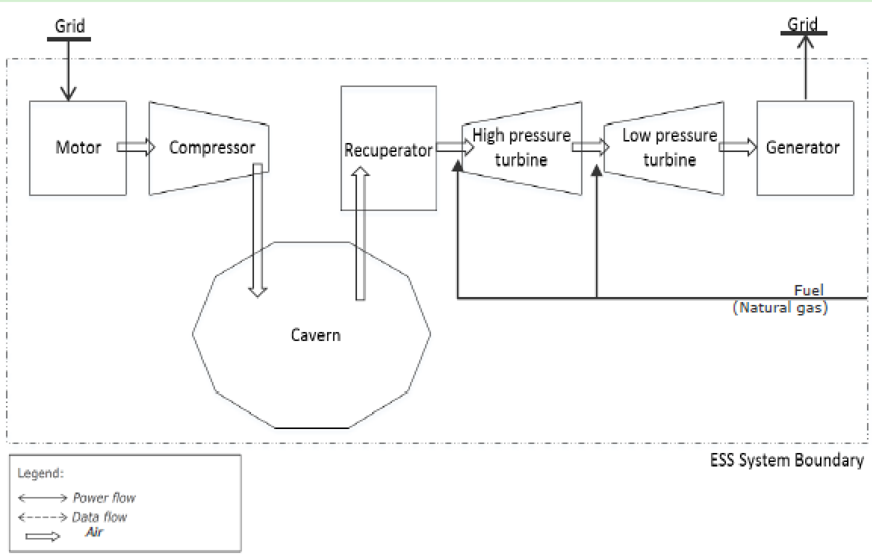


Cost Parameter/ Technology	Flywheel
Energy storage equipment cost ($/kWh)	$3,500 - $5,500
Power conversion equipment cost ($/kW)	$350 - $500
Power control system cost ($/kW)	$100-$140
Balance of system ($/kW)	$100-$125
Installation ($/kWh)	$2,000 - $3,000
Fixed O&M cost ($/kW yr)	$4 - $6
Major Maintenance ($/kW)	$200 - $300
Years between major maintenance	5

Compressed Air Energy Storage

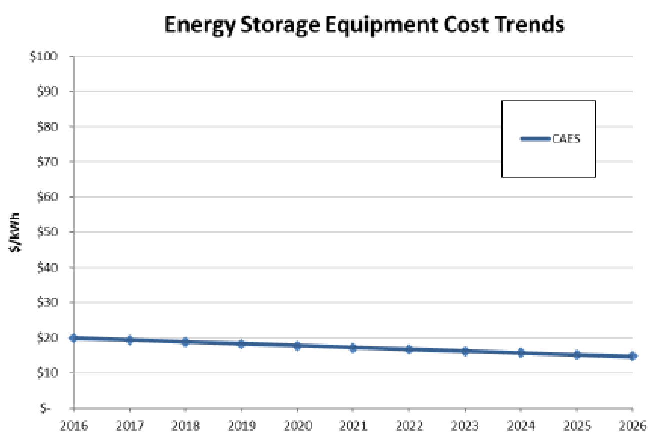
Compressed air energy storage (CAES) stores electricity by compressing air into a reservoir and generates electricity by expanding the compressed air in a gas turbine. The compression is performed by a compressor unit. Depending on the type of CAES, the heat produced during the compression is stored or released into the atmosphere. The compressed air is stored in a suitable geological formation such as salt domes, aquifers or depleted gas fields. The air is released for power generation; it is heated by combustion of natural gas and then expanded in the gas turbine.

The generation capacity of the CAES is determined by the size of the gas turbines. The compressor and the gas turbines can be dimensioned independently. The size of the geological formation determines the amount of energy that can be stored. Due in part to geological feasibility limitations, CAES has only been permanently successfully implemented in a handful of installations world-wide. Beyond the large-scale cavern systems, CAES is in the developmental and demonstration stages for underwater systems and smaller above-ground tank-based systems. These systems were not examined in detail as they are not yet commercialized.



CAES systems are designed for to support extremely long duration energy applications, in some cases, over a day of continuous energy. Due to this, DNV GL's quantitative assessment ranked CAES highly for all of the energy applications reviewed. CAES systems, purely based on their design mechanics, have a slow response time, requiring up to 10 minutes to respond to controls and serve the demand. As such, although CAES systems have large power values due to their scale, they are not well suited for applications that require quick responses such as voltage support, frequency response, or ramping for renewables.

CAES systems, again due to their large capacities, have a very low $/kWh cost. However, when the system scale is taken into consideration, the total system cost follows similar trends to other storage technologies. Underground CAES is limited in scope, but has well proven and documented performance, with two systems in operation for over 25 years. As such, the technology has been refined, with any significant cost reductions focused in the newer, developmental technologies.



Cost Parameter/ Technology	CAES
Energy storage equipment cost ($/kWh)	$10 - $30
Power conversion equipment cost ($/kW)	$400 - $500
Power control system cost ($/kW)	$100-$140
Balance of system ($/kW)	$100 - $160
Installation ($/kWh)	$5 - $10
Fixed O&M cost ($/kW yr)	$3 - $5
Major Maintenance ($/kW)	$70 - 100
Years between major maintenance	4

Thermal Energy Storage

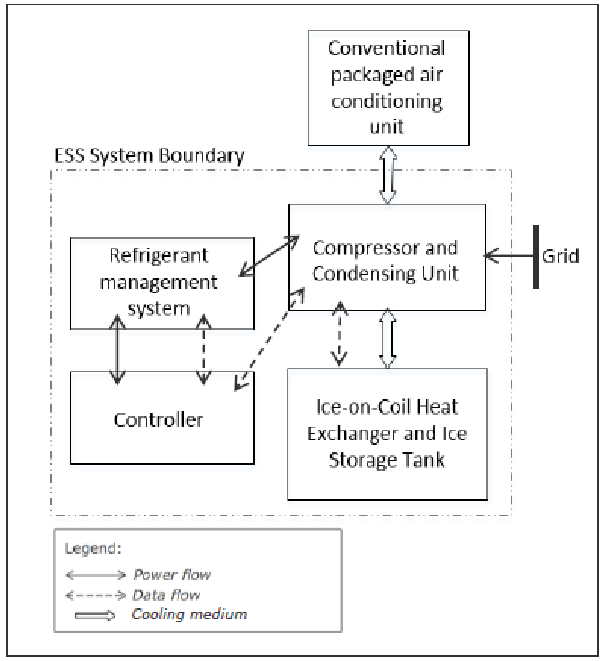
Thermal energy storage is a broad term for a variety of energy storage devices. It covers a wide range of very different technologies, wherein a medium is heated or cooled, and that energy is used at a later time. The energy to heat or cool the medium can come from the grid during off-peak times, renewable production that exceeds current demand, waste heat, or other sources. For the purposes of this report, the thermal energy storage discussed is ice energy storage.

Ice energy storage entails freezing water, or a water-based solution, at night to support space cooling during the day. The freezing process is conducted at night because lower ambient temperatures allow the ice to be made under thermodynamically beneficial conditions. Additionally, energy prices drop during the off-peak night hours. During the day, when temperatures and energy prices rise, the ice is melted and the cool air is circulated in the space. This can either reduce or eliminate the need for a conventional packaged air conditioning unit, dependent on the needs of the space and the local conditions.

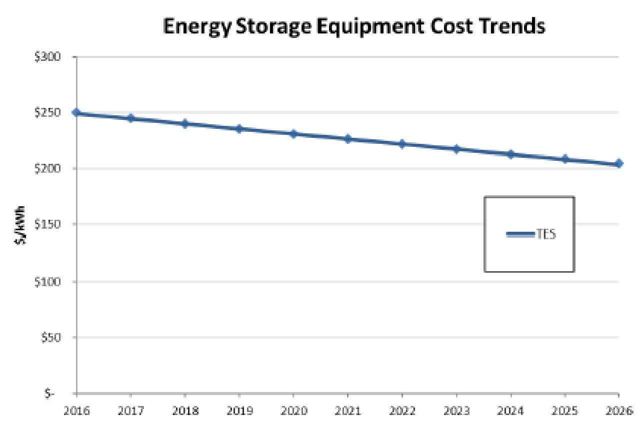
An ice energy storage system is comprised of a compressor and condensing unit, which serves to create and melt the system's ice, an ice storage tank with a heat exchanger, and a control and management system. Often, it is paired with a conventional packaged air conditioning unit, which will send the ice-cooled air into the connected space, controlled in concert with the packaged unit's functions. In cases where no conventional air conditioning unit is in place, a fan installed with the system will directly feed the air into the space.

Ice energy storage is appropriate for energy time shift and reduction in peak demand due to space cooling. DNV GL's quantitative assessment thus gave TES an acceptable rating for this application. This rating is not as high comparatively as observed with other technologies due to its limitations in application to exclusively space cooling and the associated load reduction.

TES is, however, cost competitive, with low initial cost and minimal required maintenance. As such, it may be a good option for facilities, or utilities who host facilities, with the greatest source of demand originating from cooling loads. Since peak cooling is highly seasonal and aligns with peak demand hours, this can further help to delay infrastructure upgrades otherwise required to meet these concentrated peak periods.



Cost Parameter/ Technology	TES
Energy storage equipment cost ($/kWh)	$200-$300
Power conversion equipment cost ($/kW)	N/A
Power control system cost ($/kW)	$80-120
Balance of system ($/kW)	$80-100
Installation ($/kWh)	$120-$180
Fixed O&M cost ($/kW yr)	$5-$7
Major Maintenance ($/kW)	$100 - $125
Years between major maintenance	5



Parameter/ Technology		Li-Ion BTM Residential	Li-Ion BTM C/I	Li-Ion NCM	Li-Ion LFP	Li-Ion LTO	VRB	Flywheel	CAES	TES	Notes:
Power capacity	Minimum	2 kW	250 kW	1 MW	1 MW	1 MW	200 kW	2 kW	2 MW	10 kW	Based on individual installed units or smallest proposed systems to date for energy storage. Does not include test (non-commericial), demonstration, or decommisioned systems.
	Maximum	10 kW	1 MW	35 MW	35 MW	40 MW	20 MW	20 MW	320 MW	5 MW	Based on largest installed or under construction systems to date for energy storage. Does not include test (non-commericial), demonstration, or decommisioned systems.
Energy Capacity	Minimum duration	20 min	20 min	20 min	20 min	10 min	1 hr	10 s	4 hr	3 hr	Based on average ranges. Does not include surge operation or stand by consumption.
	Maximum duration	4 hr	4 hr	2 hr	2.5 hr	2 hr	8 hr	1 hr	26 hr	6 hr	
Recharge rates		1C	1C	1C	2C-1C	3C-1C	1C-0.25C	1C	2C	3.5C	
Round trip efficiency		90%	82-83%	77 - 85%	78-83%	77-85%	65-78%	75 - 90%	55 - 70%	60 - 99%	Full ESS RTE - i.e. includes PCS, heating/cooling, and self-consumption losses
Availability	Up-time	97%	97%	97%	97%	96%	95%	98%	98%	98%	Availability guarantees being offered
	Carve Outs	72 hr/yr	72 hr/yr	72 hr/yr	72 hr/yr	72 hr/yr	1 wk/yr	72 hr/yr	72 hr/yr	72 hr/yr	Annual planned maintenance carve outs
Response time		ms	ms	ms	ms	ms	ms	ms	mins	mins	
Degradation - Percent of initial capacity lost after 10 years	Energy Applications	40%	30%	30-40%	20-40%	15-25%	5-10%	N/A	N/A	N/A	Applications: Electric Energy Time Shift, Electric Supply Capacity, Spinning, Non-Spinning, and Reserves, T&D Congestion Relief
	Power Applications	10-20%	10-20%	10-20%	15-25%	5-15%	5-10%	N/A	N/A	N/A	Applications; Regulation, Voltage Support, Load Following/Ramping Support, Frequency Response
Expected life (100% DOD, 25°C, 1C)	Years	10	10	10	10	10	10	25	30	10	Based on current manufacturer projections and guarantees; standard maintenance assumed. Full system life, including PCS and balance of plant equipment have been observed in range of 15-25 years for Li-Ion and VRB systems, implying full replacement of energy storage system components.
	Cycles	3,500	5,000	3,500	2,000	15,000	5,000	>100,000	>100,000	3,500	

Overview of CPUC and IOU Response to AB2514

NCPA and SCPPA

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INTRODUCTION

This document summarizes and supplements the webinar presented to NCPA/SCCPA members on November 29, 2016. The document is divided into two sections:

The first section focuses on policy aspects and describes the process and rationale used by the California Public Utilities Commission (CPUC, or sometimes referred to as the Commission in this memo) for determining and adopting energy storage procurement targets.

The second section focuses on storage procurement efforts by the three major California investor-owned utilities (IOUs) and reports on the progress achieved by the utilities relative to the procurement targets adopted by the CPUC.

1 CPUC POLICIES IN RESPONSE TO AB2514

1.1 Energy Storage Rulemaking Process

In response to AB2514, enacted in September 2010, the CPUC opened a rulemaking to consider energy storage issues as directed by the statute. The rulemaking was divided into two phases and eventually lasted about three years.

The first phase (Phase 1) of the rulemaking was focused on developing a basic framework to understand the various issues around energy storage, as well as to solicit policy related inputs from the parties participating in the rulemaking. Note that at the time the notion of energy storage (in particular in the form of chemical or mechanical storage) relative to the electric grid was an unfamiliar concept and much groundwork needed to be established initially in terms of basic vocabulary, applications, and regulatory issues related to energy storage, before any policy options could be considered in earnest.

The second phase (Phase 2) of the rulemaking began in August 2012 and focused on developing additional details and quantitative analysis, including development of storage use cases, cost-effectiveness studies, and continued work on policy options.

The rulemaking had extensive stakeholder participation, with over fifty organizations (including CAISO, CEC, IOUs, ORA, TURN, CCAs/ESPs, industry groups, various non-profit NGOs) submitting comments or participating in workgroups. Over the course of the rulemaking, an extensive public record was developed that served as the basis for the Commission eventually approval of its decision in October 2013, known as D.13-10-040 (and referred to as the "Decision" in this document), adopting specific energy storage deployment targets to be implemented by the California IOUs.

A wide range of work products were included in the rulemaking's record (summarized below - most of these work product items are still available on the CPUC website[1]):

- Scoping memo
- Ten Workshops
- Two Energy Division staff reports (one for each phase)
- Seven detailed use case descriptions
- Two cost-effectiveness studies
- Phase 1 Decision
- Preliminary procurement proposal
- All party meeting
- Multiple rounds of formal comments from parties
- Phase 2 Decision

Following are highlights of specific accomplishments in the each of the two phases.

In Phase 1, the Commission:

- Itemized 21 end uses of storage (see Table 1-1 b**Error! Reference source not found.**elow)
- Identified 9 categories of regulatory barriers to storage deployment (see Table 1-2**Error! Reference source not found.** below)

[1] http://www.cpuc.ca.gov/General.aspx?id=3462

- Categorized 5 distinct types of storage to be differentiated in terms of policy perspectives
- Recognized distinct flexibility benefits associated with storage in the electric grid
- Received extensive party comments regarding:
  - Advocacy of storage as a preferred resources
  - Proposed storage procurement goals/mandates
  - Wide range of other suggested policy options

Table 1-1 Storage "End Use" Framework (21 End Uses)[2]

Category	Storage "End Use"
ISO/Market	• Frequency regulation • Spin/non-spin/replacement reserves • Ramp • Black start • Real time energy balancing • Energy price arbitrage • Resource adequacy
Intermittent Generation	• Intermittent resource integration: wind (ramp/voltage support) • Intermittent resource integration: photovoltaic (time shift, voltage sag) • Supply firming
Transmission & Distribution	• Peak shaving: off-to-on peak energy shifting (operational) • Transmission peak capacity support (upgrade deferral) • Transmission operation (short duration performance, inertia, system reliability) • Transmission congestion relief • Distribution peak capacity support (upgrade deferral) • Distribution operation (Voltage Support/VAR Support) • Outage mitigation: micro-grid
Customer	• Time-of-use /demand charge bill management (load shift) • Power quality • Peak shaving (demand response), Back-up power

Table 1-2 Barrier Categories Identified by the CPUC[3]

1. Lack of definitive operational needs
2. Lack of cohesive regulatory framework
3. Evolving markets and market product definition
4. Resource Adequacy accounting
5. Lack of cost-effectiveness evaluation methods
6. Lack of cost recovery policy
7. Lack of cost transparency and price signals (wholesale and retail)
8. Lack of commercial operating experience
9. Lack of well-defined interconnection process

In Phase 2, the Commission:

[2] Presentation by Aloke Gupta, CPUC, to EUCI (Anaheim), May 19-20, 2014.
[3] CPUC (Energy Division), "Energy Storage Phase 2 Interim Staff Report" in OIR R.10-12-007, Jan. 4, 2013.

- Developed seven use cases with detailed descriptions
- Oversaw two cost-effectiveness studies of selected storage use cases
- Issued a preliminary procurement proposal outline
- Approved a decision adopting an energy storage procurement framework

Notably, significant work went into the development of seven detailed use cases with the help of stakeholder workgroups to understand how energy storage could be used in the power grid. Two separate cost-effectiveness studies involving a range of selected storage cases and technologies were completed (one by EPRI, and the other by DNV GL) to assess potential benefits vs. costs of energy storage technologies under various use case and future market/system conditions. The results of both studies were referenced in the Decision. Lastly, in Phase 2, a preliminary proposal with specific procurement targets was floated via Commissioner Peterman's Assigned Commissioner's Ruling (ACR), essentially as a trial balloon.[4] This was followed by an all-party meeting, where parties provided in person feedback to the assigned commissioner, along with extensive party comments formally submitted to the CPUC.

The feedback on the ACR, as well as various findings based on the extensive record developed during the rulemaking, was captured ultimately into an "Energy Storage Procurement Framework" described in the Decision (D.13-10-040) adopted by the Commission in October 2013. The "Framework" included a seven year procurement energy storage roadmap with specific targets, program goals and eligibility, program rules, guidelines on target flexibility, reporting and program evaluation requirements, and a cost-effectiveness evaluation protocol to be used by the IOUs to report results of procurements to the Commission.

1.2 Highlights of the Energy Storage Decision

Key highlights of the Decision are summarized here. The table below captures the specified procurement targets over time prescribed by the Decision for each utility.

[4] Commr. Peterman's ACR of June 10, 2013 in CPUC's OIR R.10-12-007.

Table 1-3 CPUC Adopted Energy Storage Procurement Targets (in MWs)[5]

Storage Grid Domain Point of Interconnection	2014	2016	2018	2020	Total
Southern California Edison					
Transmission	50	65	85	110	310
Distribution	30	40	50	65	185
Customer	10	15	25	35	85
Subtotal SCE	**90**	**120**	**160**	**210**	**580**
Pacific Gas and Electric					
Transmission	50	65	85	110	310
Distribution	30	40	50	65	185
Customer	10	15	25	35	85
Subtotal PG&E	**90**	**120**	**160**	**210**	**580**
San Diego Gas & Electric					
Transmission	10	15	22	33	80
Distribution	7	10	15	23	55
Customer	3	5	8	14	30
Subtotal SDG&E	**20**	**30**	**45**	**70**	**165**
Total - all 3 utilities	**200**	**270**	**365**	**490**	**1,325**

As can be seen in the table above, the three IOUs together were to procure a total of 1,325 MW of energy storage by 2020, acquired incrementally through four biennial solicitations, starting in 2014 (then again in 2016, 2018, and ending in 2020). In addition to the specified procurement timeline, the targets for each utility were sub-divided into "storage grid domains" based on the storage asset's point of interconnection to the grid (that is, connected to the transmission network, or connected to the distribution network, or sighted on customer premise on the customer side of the utility meter. Utility ownership of storage assets was capped at 50% of the cumulative target.

The Decision provided a fair amount of procurement flexibility to the utilities in terms of shifting targets between storage grid domain "buckets", accelerating procurement forward in time, or deferring procurement to a later date in case of available procurement options not being satisfactory or reasonable.

To be eligible for counting toward the targets, the energy storage asset procured by the utility could be based on any commercially available storage technology (that complied with the technology criteria described in AB 2514 – with the exception of pumped hydro larger than 50 MW, which was specifically excluded by the Decision), must be operational before the end of 2024, and must satisfy at least one or more of the three specified project purposes or objectives (listed below), per the Decision:

1. Grid optimization (including peak reduction, contribution to reliability needs, or deferment of transmission and distribution upgrade investments)
2. The integration of renewable energy; or
3. The reduction of greenhouse gas emissions (to 80 percent below 1990 levels by 2050, per California goals).

The Decision allowed the IOUs to count customer-sited or customer-owned energy storage systems toward it's procurement target, whether or not the project received incentives from the utility's customer-side

[5] CPUC Decision D.13-10-047, p.15.

storage incentive programs (such as PLS or SGIP – discussed later), provided the storage device satisfied one of the project objectives listed above.

Finally, a procurement target was also assigned to ESPs/CCAs equal to 1% of their respective 2020 peak loads.

A key point to note is that the Decision required the utilities to procure storage projects that pass a reasonableness test, as is typically the case in most utility procurements. In other words, the utilities must seek Commission's approval of proposed procurement contracts by demonstrating that the storage project being procured is in the interest of ratepayers and cost-effective (although there is often context-specific discretion exercised by the Commission in judging whether these standards have been).

To the disappointment of some, cost data associated with storage projects procured and deployed was prohibited from disclosure to the public by the utilities. Per the Decision, procurement data was to be considered confidential, in line with long standing practice established about ten years ago in another CPUC decision D.06-66-066 to protect the interest of ratepayers.

1.3 Stakeholder Input to the CPUC

The policy aspects of how the CPUC arrived at its conclusions incorporated in the Decision in terms of the available public record are discussed here.

AB2514 essentially presented two potential policy outcomes to be contemplated by the CPUC while considering the desirability of energy storage procurement: one, adopt specific procurement targets if it was "appropriate" to do so; in addition, or as an alternative, pursue a range of policy options to support or encourage energy storage deployment.

In reviewing the extensive party input received by the CPUC, the stakeholder positions could be summarized into a range of strategic approaches to address AB2514, as listed below (with the most conservative recommendation at the top and the most aggressive approach at the bottom of the list):

1. Business as usual (essentially "do nothing")
2. Remove barriers to deployment
3. Induce or catalyze market transformation
4. "Directed" long term market development roadmap

With respect to the first approach, some parties argued that it was not at all appropriate for the Commission to be setting targets at the current juncture (in 2013). Their concern was that storage technology was extremely nascent, very little operational experience existed, and a procurement mandate could become counterproductive to storage deployment progress. These parties were more comfortable relying on technology evolution and market forces to drive adoption of energy storage into the grid system in an organic manner.

The second approach supported by some parties encouraged the CPUC to be a bit more pro-active by working to break down regulatory and market barriers (particularly the barriers that had already been identified earlier in the rulemaking) and "levelize the playing field" for energy storage to compete with other alternatives available to the utilities to address specific system needs. These parties also took issue with target setting but seemed to suggest a compromise in that procurement targets could sometimes be appropriate provided certain conditions were met.

Some parties advocated a third approach. While still objecting to formulation of targets, these parties supported the CPUC driving some type of market transformation focused on energy storage, with the expectation that grid needs and market forces would eventually drive storage deployments. As suggested by the parties, the transformation process could be initiated, for example, by encouraging more storage demonstration projects to accelerate gaining storage operational experience.

Finally, the last and the most aggressive strategy listed above suggested by the parties asserted that a long term procurement roadmap with specific targets was appropriate at this time for a variety of reasons (such as large scale storage deployment being critical to meeting California's 2050 clean energy goals and important in improving cost effectiveness, breaking down deployment barriers, and providing key benefits to ratepayers). These parties believed that this path was similar to the progress already experienced with RPS (Renewable Portfolio Standard), CSI (California Solar Initiative, or DR (Demand Response), where long term targets were set to drive utilities procurements. A wide range of specific targets were presented by these parties. The high end ranged from 8 to 12 GW (which amounted to about 12 or 18 % of 2020 peak load). One party suggested 4 GW of distributed storage (that is, storage projects spread out near major load pockets, as opposed to developing large, centralized storage plants connected to the transmission grid at some remote point). On the low end, 1 GW was suggested as sufficient to drive learning experience and focused evaluation of storage technologies by the utilities.

Ultimately, the CPUC rejected the first recommendation but essentially adopted some combination of all three more aggressive approaches, including setting long term procurement targets for energy storage deployment.

1.4 Policy Rationale in Support of Procurement Targets

The rationale articulated by the CPUC for adopting the storage procurement framework, as discussed in its Decision, addressed a variety of factors.

The CPUC made findings in the rulemaking that energy storage was a critical technology needed to support California's 2050 clean energy goals and that the technology had the potential to transform the electrical system and provide critical services for 1) grid optimization, 2) integration of renewable power, and 3) minimization of greenhouse gas emissions. It was thus important to push forward with integrating energy storage resources into the power grid.

The CPUC also noted that there were a variety of market/ regulatory barriers impeding the deployment of energy storage and that this situation was not too different from that involving renewable energy technologies at an earlier point in time. The CPUC concluded that the most effective means to deal with these barriers was to develop a long term sustained strategy that would allow the utilities and the industry to work together in bringing forth projects to provide long term benefits. The long term sustained strategy meant adopting storage procurement targets to achieve market transformation.

To recap, a key goal of the Commission's Decision was achieving energy storage market transformation and accelerate the breakdown of market/regulatory barriers, reduction of costs, and deployments of storage into the grid over time. The Decision was adopted by a unanimous vote at the Commission.

The question of how the CPUC arrived at the specific numerical targets is more difficult to address as the CPUC chose not to discuss in its Decision the thought process that went into developing these targets. However, a careful review of the public record and the general context of the rulemaking in 2013 could provide some insights into this.

Several data points related to potential long term storage needs in California had been accumulated before the Commission began contemplating procurement targets. There was the CEC PIER report[6] suggesting that about 2 to 4 GW of fast acting storage would be needed by 2020 to integrate renewables (in the context of 33% RPS). There was a 2010 KEMA (now DNV GL) study[7] that examined the impact of 33% RPS on the regulation market and concluded that approximately 1200 MW of energy storage participating in CAISO markets provided a superior result (in terms of emissions) compared to about 4800 MW of conventional

[6] CEC PIER Final Project Report, "2020 STRATEGIC ANALYSIS OF ENERGY STORAGE IN CALIFORNIA" 2011. http://www.energy.ca.gov/2011publications/CEC-500-2011-047/CEC-500-2011-047.pdf.
[7] KEMA, inc. "Research Evaluation of Wind and Solar Generation, Storage Impact, and Demand Response on the California Grid" 2010. http://www.energy.ca.gov/2010publications/CEC-500-2010-010/CEC-500-2010-010.pdf.

resources. Lastly, there were stakeholder recommended targets discussed earlier, ranging anywhere from 0 to 12 GW.

In addition, there was storage deployment activity already in progress among the IOUs.

By the time of the Decision, the IOUs had already installed about 93 MW of energy storage on the grid (see Table 1-4 below), acquired through various programs, mostly experimental or demonstrations/pilots as approved in earlier CPUC decisions.

Also, prior to the Decision, the CPUC had taken other small but significant steps in directing the IOUs to procure or encourage energy storage for commercial operation (see Table 1-4 below). Between the demand side (or customer-side) incentive programs (SGIP, PLS-permanent load shifting) approved in CPUC decisions many months prior to the Decision, as well as the 75 MW energy storage procurement directive to SCE / SDG&E to address the capacity issue in Southern California, there was an aggregate of 140 MW of energy storage procurement already in the works when procurement targets were being considered for the Decision.

Table 1-4 "Pre-existing" Energy Storage Prior to the Decision[8]

"Pre-existing" energy storage deployment ▪ PG&E ▪ SCE ▪ SDG&E	 ▪ 12 MW ▪ 30 MW ▪ 51 MW	 93 MW Total
"Pre-existing" authorized storage procurements ▪ Demand side incentives ▪ SCE Local Capacity Reliability ▪ SDG&E Local Capacity Reliability	 ▪ 65 MW ▪ >50 MW ▪ >25 MW	 140 MW Total

With these various data points on existing and pending storage deployments and potential future needs that could be partially satisfied by energy storage in the background, the CPUC settled on the procurement targets listed in Table 1-3, which could be considered to be in the lower range of the available data points.

It may be interesting to highlight some observations with respect to the adopted procurement targets (Table 1-3):

- The total target of 200 MW in 2014 was just a bit more than 168 MW, which was the sum of 93 MW (the amount of storage already installed by the IOUs prior to the Decision - recall IOUs were allowed to count existing storage projects as credits against the targets) and 75 MW (the amount of storage that the Commission had already directed SCE / SDG&E to procure *before* the Decision in order to address the local capacity shortage anticipated in Southern California). Adding in 65 MW expected from demand side incentive programs yielded a total of 233 MW in "pre-existing" deployed or pending energy storage, a quantity larger than the 2014 target of 200 MW.
- The cumulative target of 1,325 MW was approximately 2% of the peak load projected for 2020.
- The growth in targets from 200 MW to 1,325 MW over 4 biennial solicitation cycles amounted to about 35% growth per cycle (or about 15% compounded annual growth rate, compared to much higher growth rates already seen in the adoption of various renewable energy technologies).

[8] Presentation by Aloke Gupta, CPUC, to EUCI (Anaheim), May 19-20, 2014.

- The split of targets between the IOUs followed roughly the ratios of the projected peak demand of the utilities (with SCE's & PG&E's aggregate demand thought to be approximately equal and several factors larger than SDG&E's).
- The target at transmission level appeared to be slightly more than half of the total target, with the other half at the distribution level (divided between utility-side distribution and customer-side behind-the-meter).

As to whether or how the procurement targets relate to resource planning or system driven needs, the Commission was clear in the Decision that it was not basing the targets on specific system needs but felt it had the discretion to set targets based on perceived policy driven needs to achieve market transformation. It may be helpful to quote at length directly from the Decision on this point to understand the Commission's thinking:

"System need determinations are required in CPUC generation resource procurement proceedings, such as LTPP [Long-Term Procurement Planning]. ...

In other policy areas promoting preferred resources, such as renewables, the California Solar Initiative and demand response, the Commission has not set targets based on a system need determination, but rather administratively determined procurement requirements to meet public policy objectives. To the extent that energy storage is treated akin to a "preferred resource," as it has been designated in D.13-02-015, the Commission has clear precedent to administratively establish storage procurement targets without a system needs determination.

In addition to these precedents, we have considered the criteria articulated in Section 2836.2 [AB2514] in determining the procurement targets adopted today. We have examined through workshops existing energy storage projects, reviewed the available information from CAISO, considered the integration of energy storage technologies with other programs, and proposed targets that we believe would allow for procurement of technologically viable and cost effective storage projects. We adopt the targets presented in Table [3 in this document], since they strike a balance between both achieving realistic targets in fulfillment of approved principles and minimizing costs with proper planning and safeguards.

We agree with parties that being overly prescriptive in a nascent market may have some unintended market consequences. Consequently, we find that it is reasonable to adopt a broad framework initially and add additional details later, if necessary, as more experience is gained and lessons can be applied."9

In the longer term, it was hoped that procurement of energy storage would be increasingly tied to need determinations within the Commission's resource planning proceedings.10

In terms of actual procurement experience and outcomes in the last few years, as will be apparent in the next section, much of the procurement to date in fact has been driven by specific power grid related needs.

[9] CPUC Decision D.13-10-40, p. 24.
[10] Commr. Peterman's ACR of June 10, 2013 in CPUC's OIR R.10-12-007, p. 15.

2 CA IOU PROCUREMENT PROGRESS RELATIVE TO CPUC TARGETS

This section discusses the utilities' actual progress in procuring energy storage relative to the targets adopted in the Decision.

2.1 IOU Procurement Efforts

Since 2013, there have been multiple different procurement efforts, summarized in Table 2-1 below, where utilities have procured energy storage.

Table 2-1 IOU Procurement Efforts since 2013[11]

SCE / SDG&E	• LCR (Local Capacity Reliability) RFO
SCE	• Aliso Canyon RFO • Preferred Resources Pilot (PRP) II RFO • Distributed Energy Storage Initiative RFO
All IOUs	• Energy Storage RFOs (2014, 2016) • Customer Incentive Programs • DRAM Auctions • EPIC (R&D) program • General Rate Cases (GRCs)

While some procurement efforts were specifically focused on energy storage, several of these procurement efforts were open ended in that offers based on non-storage resources (such as DG, DR, and in some cases conventional generation), as well as storage resources, were eligible to bid in.

One of the best known solicitation in terms of impact on the storage industry was the local capacity reliability (LCR) RFO that both SCE and SDG&E launched in 2013 to seek new peak capacity. This RFO was driven by the need to address the capacity shortfall triggered by OTC (thermal) and SONGS (nuclear) plant retirements. More recently, the Aliso Canyon RFO was driven by the Aliso Canyon emergency. Of course, all utilities were also engaged in the Decision mandated energy storage solicitations (issued in December 2014) - only one has been completed to date, with next one launched just this month (December 2016, in line with the 2016 cycle as specified in the Decision). In addition, there are on-going customer incentive programs (PLS, SGIP) at all three utilities for encouraging customer side storage deployments, with PLS incentives focused on thermal storage based permanent load shifting and SGIP incentives directed at primarily battery technologies.

Storage based offers are also eligible to bid into recently initiated, and periodically conducted, DR auction market (DRAM). IOUs have procured/deployed some energy storage projects via general rate cases (GRCs) that IOUs file with the CPUC every three years on a staggered basis. Finally, the IOUs have funded a few storage projects via the EPIC R&D program.

[11] Table contents compiled by the author.

2.2 Storage Procurement Status

As noted earlier, the utilities had already deployed 93 MW through a variety of experimental programs prior to the Decision, which the IOUs were allowed to count against the target of 1,325 MW.

As of November 2016, even though only one round of energy storage specific solicitation required by the Decision has been completed, the utilities have already procured a total of 735 MW, about 55% of the cumulative targets (see Table 2-2 below).

Table 2-2 IOU Storage Procurement Progress (all data in MWs, except %)[12]

all data in MWs, except %)[13]

	Pre-exist	2020 Cum Target#	Under Contract* (to date)#	% Completed	Difference vs. Target	Pending RFOs (Dec. 2016)
SCE	30	580	522	90%	58	20
PG&E	12	580	96	16%	484	115
SDG&E	51^	165	117	71%	48	4 + 140
Totals	93	1,325	735	55%	590	139 + 140

* As of Nov 15, 2016 (some recent contracts still pending CPUC approval or rejection)

Includes pre-existing and customer-side storage projects

^ Includes 40 MW Lake Hodges Pumped Hydro

Note that the total procured to date ("under contract" in above table) includes customer-sited or customer-owned energy storage systems (even if *not* contracted by the utility, such as storage projects receiving incentives from utility's customer storage incentive programs), which are permitted to be counted by the IOU against its target per the Decision.

As can be seen in the table's breakdown above, SCE has already contracted 90% of its assigned target. SDG&E has also made substantial progress, procuring about around 70% of its target. PG&E has contracted the smallest quantity to date, at around 16% of its target.

Given where the utilities are at this point in time, with over 55% of the cumulative target procured already, the "difference vs. target" column in the above table shows the portion that still remains to be procured by each IOU per the Decision targets (totaling 590 MW).

The last column "pending RFOs" in the same table shows the amounts that are being sought in the storage RFOs issued by the three IOUs this month (December 2016). SCE is seeking at least 20 MW (at transmission level). PG&E has issued a much larger request, with at least 115 MW (spread into all three domains) of storage projects being sought. SDG&E's request is a bit more complicated; it is seeking at least 4 MW of distribution-level storage; separately, SDG&E is also soliciting at least 140 MW of "preferred resources", a category in which energy storage offers are eligible to bid, in competition with offers based on

[12] Table data compiled by the author.
[13] Table data compiled by the author.

DG, DR, EE, etc., but excludes fossil-based sources - the portion of the 140 MW being sought by SDG&E that may end up being storage is unknown at this point.

2.3 Procurement Drivers

At the time when the Decision was issued, there was uncertainty as to what extent energy storage could satisfy system needs at satisfactory cost effectiveness levels. Contrary to what might have been expected by many at that time, most of the energy storage projects to date in fact have been procured to meet real power grid needs.

The specific system needs have been largely due to reliability issues in Southern California. Before the Decision, the CPUC's resource planning process had already identified a long-term local capacity shortage in Southern California, primarily as a result of OTC retirements, and directed SCE and SDG&E to launch solicitations to seek new capacity assets. Subsequently, the retirement of SONGS further aggravated the capacity shortage. Then more recently, the emergency associated with the Aliso Canyon situation created an additional short term reliability need, again in the form of peak capacity, in SCE's and SG&E's territories. All of these factors became major drivers for the two IOUs to procure energy storage projects to partially meet the anticipated peak capacity requirements.

The above factors are the primary reason that SCE and SDG&E have been able to make rapid progress against their targets (as noted in **Error! Reference source not found.**), with SCE at 90% and SDG&E at 7 0% procurement levels. Thus, with respect to PG&E's progress, the progress data should not been seen as an indication of poor execution or underperformance on the part of PG&E. In hindsight, SCE and SDG&E were able to obtain storage assets to partially satisfy the system reliability needs, a situation not really anticipated. Going forward, the proposed retirement of Diablo Canyon plant may help accelerate need-based energy storage procurement in PG&E's territory in line with higher renewables and demand side investments.

Lately, the CPUC has taken a deeper interest in distributed energy resources (DER), with multiple proceedings looking at different DER-related issues to encourage development of DER resources as another tool to address demand reduction and provide "non-wire" alternative to distribution reliability needs and upgrades. Some distributed storage projects have been procured by the utilities for distribution deferral. Given the few contracts issued for deferral project, it appears that the economics have been more challenging for energy storage to meet of the utilities are still learning how best to leverage energy storage for distribution needs.

2.4 Procurement Highlights

The results of the first and most recent procurement effort may be of particular interest to discuss in more detail.

The first formal solicitation for commercial deployment of energy storage was the 2013 SCE LCR RFO. The objective of this RFO was to seek up to 2000 MW of peak capacity, of which at least 50 MW was required to be in the form of energy storage - per the CPUC directive (issued in a separate decision several months before the Decision). Potentially, storage procurement could be even higher than 50 MW as the CPUC had authorized SCE to procure up to 600 MW in "preferred resources", a category that included energy storage.[14]

SCE received over 1000 offers (recall that this solicitation was all-source that allowed both storage and non-storage bids) and over half[15] of them involved energy storage. That there would be such a large number of storage-based offers was perhaps an unexpected development and suggested the storage industry felt ready to engage in large scale commercial projects.

After completing the required due diligence of the offers received, SCE chose to contract with four storage bidders for a total of 261 MW. Of these four, one contract was with AES for a single, utility-side, large plant of 100 MW (x 4-hour) capacity connected to the transmission grid (due to go online by 2020). The remaining 161 MW (x 4-hour) was contracted with three vendors who planned to aggregate many storage devices installed at different customer sites (on customer side of the utility meter) to deliver the required capacity to SCE (more details later). The three vendors chosen to deliver the 161 MW total capacity were: STEM for 85 MW, AMS for 50 MW, and Ice Energy for 26 MW. All three contracts required customer side projects to begin coming online starting in 2017, with the total contracted capacity to be available by 2020.

At the time of the Decision, there probably was some anxiety about how energy storage will actually stack up in commercial procurements. The results of SCE's LCR RFO provided some re-assurance that the storage technology and the industry appeared ready for prime time and that storage resources could be competitive with conventional alternatives, at least under specific circumstances and applications.

The most recent RFO, which was triggered by the Aliso Canyon emergency, was also conducted by SCE and launched in May 2016. By September (in less than 5 months), SCE had already selected five different contracts totaling 57 MW on a fast track basis, with the projects required to be online by the end of 2016 or Jan 2017 (not 2020).

The results of this RFO were also considered surprising in that it demonstrated that storage could be deployed quite rapidly on demand, provided of course that the proposed storage project was associated with key favorable conditions, such as the host site being located in the target geography with existing transmission interconnection capacity, etc., to be able to be deployed quickly. Still, these contracts suggested that the industry's energy storage supply chain could accommodate large quantities on a short notice and that the engineering challenges of design, construction, and O&M for large storage projects could be tackled quickly.

At this point, most of the contracts aggregating to 735 MW procured to date (per Table 2-3) have already been approved by the CPUC (a few are still pending), suggesting that the utilities have been able to demonstrate to the CPUC's satisfaction that the contracted projects are cost-effective and in the interest of the ratepayers. Some contracts have been rejected by the CPUC for not satisfying the reasonableness test. This outcome could also be regarded as perhaps a positive surprise. An important caveat should be noted here: only a very small portion (a few customer-side projects) of the 735 MW procured has actually been built out and commissioned; it can be argued that the capability of energy storage technology to perform in the field has yet to be proven.

[14] Presentation by Aloke Gupta, CPUC, to EUCI (Anaheim), May 19-20, 2014, p.16.
[15] Presentation by Aloke Gupta, CPUC, to EUCI (Anaheim), May 19-20, 2014, p.16.

2.5 Procurement Split by Storage Grid Domain

Table 2-3 below shows how the procurements to date are spread out in terms of storage grid domain for each utility. This table illustrates another surprising result in that the customer side projects account for the largest share, almost 49% (or 357 MW), of the total 735 MW contracted to date. This is 80% higher than the aggregate customer-side target (200 MW) assigned to the utilities. More recently, in a decision this year, the CPUC has granted additional flexibility to the utilities to count customer side procurements against transmission or distribution domain targets.

Table 2-3 Storage Procurement Breakdown by Storage Grid Domain (in MWs)[16]

	2020 Cum Target	Transmission-Connected	Distribution-Connected	Customer-Side	Under Contract* (to date)
SCE	580	310	185	85	522
		157	35	330	
PG&E	580	310	185	85	96
		73	9	14	
SDG&E	165	80	55	30	117
		98	6	13	
Totals	**1,325**	**700**	**425**	**200**	**735**
		328	**50**	**357**	

Presently, the vast majority of customer-side procurement is in SCE's territory. As discussed later, the contracts involving customer-side storage rely on third party aggregators to offer aggregated "load reduction" for at least 4 hours (in the form of customer-side storage devices discharging for the duration) on demand as dictated by real-time grid conditions.

2.6 Procurement Business Models

The basic business models that have been utilized by the utilities, or could be in the future, as a basis for storage procurement contracts are summarized in Table 2-4 below.

Table 2-4 Business Models Used in Storage Procurement Contracts[17]

	Ownership	Contract Type	Contract Terms
1	Third-party (customer-side)	DER Aggregation (load reduction)	Periodic payments, performance penalty
2	Third-party (utility side)	Tolling Contract	
		RA-only Contract	
3	Utility (utility-side)	Design/Build/Transfer, Build/Own/Transfer	Purchase @ transfer (ratebase)
4	Utility (customer-side)	Design/Build/Transfer, Build/Own/Transfer	Purchase @ transfer (ratebase)

[16] Table data compiled by the author.
[17] Table content compiled by the author.

1. Third-Party Owned (customer-side)

The contracts for third-party owned, customer-side storage involve a form of DER aggregation, where the third party aggregator is required to deliver a predictable/contracted amount of load reduction for the required duration (by discharging the storage fleet to offset the load of the host customers associated with the storage fleet). The storage assets are owned by the third party and reside on the customer side of the utility's meter. In terms of finances, the contract typically calls for periodic fixed payments by the utility, with a penalty clause that is triggered if the third party aggregator fails to perform. However, the utility payments are not the only source of revenue available to the third party under this arrangement.

In the case of contracts such as with STEM & AMS, there are other revenue streams involving demand charge reduction, renewable smoothing, backup/reliability service, and other services the third party promises to provide to the host customer. The utility generally has no insight into the value exchanged between the end (host) customer and the third party, and details associated with that value exchange are not part of the contract between the third party and the utility (however, those matters are addressed in the contract between the third party and the host customer).

Even though there may be multiple types of dispatches of the storage devices occurring in line with the services being offered to the host customer, from the utility's perspective, the arrangement is straightforward in that the third party aggregator is committed to deliver a predictable amount of load reduction on demand to offset the system peak, enabling the utility to meet its capacity reliability obligations.

In the case of Ice Energy, the contracted load reduction is achieved through permanent load shifting: the thermal storage asset, again located on customer-side of the meter and owned by the third-party aggregator, routinely stores energy ("charging") during off-peak hours by freezing a suitable liquid solution into "ice"; the storage device releases the stored energy ("discharging") during the high temperature peak hours by circulating and cooling the air through the ice (which reverts back to the liquid state in this process) to alleviate the need for electrical air conditioning. This of course results in demand charge savings to the host customer, while appearing as a relative "load reduction" on the utility's distribution grid.

In both cases, as discussed above with the aggregation contracts, there are multiple revenue streams that accrue to the third party aggregator. The value exchange between the host customer and the third party is used to determine the capacity price the third party would be willing to offer to the utility in order to recover the net cost of the storage asset (after accounting for the other revenue streams from the host customer). In the absence of the host customer revenue stream, presumably the third party's offer price to the utility would be higher. Hence, with customer-side aggregated storage, the utility benefits indirectly through a lower price capacity offer that the third party is able to make because the third party has access to alternative revenue from the host customer to partially offset the total cost of the storage asset.

2. Third-Party Owned (utility-side)

In case of a utility side storage asset, two types of contracts have been generally used by the IOUs: an RA only contract or a tolling contract.

In the former RA only contract case, the third party controls the dispatch of the storage asset under its ownership. Hence, it is up to the third party to estimate how much margin could be earned by dispatching the storage device into ancillary services markets, and then to attempt recovery of the remaining net cost (after adjusting for the margin) via the long term capacity price that a utility would be willing to commit to under the contract.

In the latter tolling contract case, the utility controls the dispatch of the third-party owned storage asset; hence, it is up to the utility to estimate the margin the asset could earn for bidding ancillary services, and then to determine whether net capacity value of the asset (capacity price offered by the third party minus the margin earned in the markets) is satisfactory compared to other alternatives available to the utility.

Both RA only and tolling contracts involve periodic payments by the utility subject to a non-performance penalty. But the assets are owned and financed by the third party over the life of the contract. In both cases, the utility's risk is thus mitigated in that the storage assets are *not* committed to the utility's capital ratebase; if the third party fails to perform, the utility can of course cancel the contract, with losses born by the third party, and seek alternative suppliers to step in.

3. Utility-Owned (utility-side)

The third model is the more traditional utility-owned purchase of an asset that is financed through the utility's capital ratebase. This approach is sometimes referred to as "build, own, transfer", or "design, build, transfer." A third party, typically an EPC, constructs and commissions the asset while owned and financed by that third party and then transfers the ownership of that asset to the utility. The utility makes a cash payment to the third party and the asset cost is incorporated into the utility's capital ratebase on a depreciating basis over the life of that asset, financed through distribution or transmission charges assessed to end customers.

4. Utility-Owned (customer-side)

This model is similar to the arrangement that currently exists between some members of SCCPA and Ice Energy. However, this option, while permitted by the Decision, has not yet been exercised by the California IOUs in procurements to date.

Appendix C: SCPPA RFI on Energy Storage Technologies

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY

Request for Information on Energy Storage technologies

Issuance Date: February 23, 2017

Response Deadline: March 30, 2017

I. Introduction

The Southern California Public Power Authority (SCPPA), on behalf of its Member Utilities, is hereby requesting information regarding energy storage technologies, as well as the capabilities and qualifications of Respondents to this Request for Information (RFI) to develop or coordinate the development of those respective technologies referenced and offered in responses to this RFI. More specific details on the information being requested are provided below in Section III – Areas of Interest.

SCPPA is interested in evaluating this information and discovering all Respondent's capabilities related to the specified Areas of Interest to make an informed decision and potentially proceed to more specific discussions or formal solicitations with one or more qualified Respondents to this Request for Information (RFI).

Responses to this RFI are due on or before 4:00pm PST, on March 30, 2017, as described below in Sections III and V.

II. Background

SCPPA is a joint powers authority and a public entity organized under the California Joint Exercise of Power Act found in Chapter 5 of Division 7 of Title 1 of the Government Code of the State of California, and through the SCPPA Joint Powers Agreement, for the purposes of planning, financing, developing, acquiring, constructing, operating and maintaining projects for the generation or transmission of electric energy. SCPPA also facilitates joint service contracts, at the request of its members, to aggregate like project efforts amongst its Members for the purposes of developing energy efficiency, demand response and resource procurement Programs or Projects to improve operating efficiencies and reduce costs.

Membership of SCPPA consists of eleven cities and one irrigation district, which supply electric energy within Southern California, including the municipal utilities of the cities of Anaheim, Azusa, Banning, Burbank, Cerritos, Colton, Glendale, Los Angeles, Pasadena, Riverside, and Vernon, and the Imperial Irrigation District. The management of SCPPA is under the direction of an Executive Director who is appointed by the Board.

III. Areas of Interest

SCPPA members have expressed interest in gathering technical assessments and related cost information, to the extent possible, for many different energy storage technologies to meet the needs of their respective electric utilities and the communities that they serve. Recognizing that the energy storage market is broad and multiple media can be used to store energy, SCPPA is requesting and accepting information offered by Respondents on any and all technologies that can be used by electric utilities or their customers to improve their respective operating efficiencies and/or reduce operating costs of their facilities or homes.

The specific, detailed information that SCPPA is requesting on any such energy storage technology includes, but is not limited to:

1. **Storage Type**
   - Biological
   - Chemical
   - Electrochemical
   - Electrical
   - Mechanical
   - Thermal
   - Other

2. **Electric System Applicability**
   - Transmission Services
   - Distribution Services
   - Generation Services
   - Customer / Behind-the-Meter Services

3. **Storage Technology Use / Function**
   - Bulk Services
     - Peak Load Shift
     - Supply Capacity
   - Ancillary Services
     - Frequency Regulation
     - Spin & Non-spin capacity
     - Voltage Support
     - Black Start
     - Variable Resource Load Following
   - Transmission & Distribution Services
     - Infrastructure Deferral
     - Congestion Relief
     - Transmission Capacity
   - Commercial Industrial Services
     - Power Quality
     - Power Reliability
     - Energy Time Shift
     - Demand Charge Management
   - Residential Services
     - Power Quality
     - Power Reliability
     - Energy Time Shift

4. **Storage Technology Maturity**

5. **Storage Technology Physical Make-up / Construct**
   - Storage medium
   - Technology overview
   - Cycle/"Round trip" efficiency
   - Rate of charge and discharge and efficiency declines with varying rates
   - Size/dimensions and footprint
   - Safety Considerations (e.g. environmental and/or physical hazards) and potential mitigation

6. **Exemplary Prices**
   - Installed cost ($/kW)
   - Life cycle cost ($/kW-year)
   - Energy Cost ($/MWH)

SCPPA recognizes and acknowledges that some of these factors, particularly prices, will depend on the capacity of (and possibly the duration of time required from) the energy storage facility being built as well as location. While this RFI is not intended to specify a certain storage project of any particular size, duration, cycling capability or other such design parameter, it is expected that SCPPA and/or one or more of our Members will use the information obtained in this RFI to develop and issue subsequent Requests for Proposals for well-defined storage projects. One example of such an opportunity is a potentially impending RFI from the Los Angeles Department of Water and Power for the development of a large-scale storage project to support the integration of intermittent renewable energy into their transmission system.

To that end, SCPPA is requesting that in addition to the necessary supporting documentation of the system(s) being offered, all responses to the RFI must include the full price of at least one (1) size-specific example of the storage system – with a clear delineation of the capacity and duration (in MW and MWH) being offered – without consideration or inclusion of land acquisition costs. However, SCPPA is also requesting that Respondents clearly delineate their ability to develop energy storage system(s) with point-of-delivery/point-of-receipt in one or more of the balancing authorities (BA) that one or more SCPPA Members operate within. These BAs include the CA ISO, LADWP BA, and IID's BA.

All of the parameters referenced above shall be identified and included in Appendix A that must be included for any and all energy storage system offerings provided by Respondents to this RFI.

Timeline / Schedule*

SCPPA RFI on Energy Storage Technologies Selection Process	
Schedule of Requirements	**Target Date(s)**
Issue RFI	February 23, 2017
Questions for clarification Due	March 7, 2017
Responses Due	March 30, 2017
Review of Responses	April 2017
Interviews (if necessary)	April – May 2017, if needed
Selection of Respondent(s)	April – May 2017

*Timeline/Schedule is subject to change.

The deadline to submit questions on this RFI will be 4:00PM (PDT) on **March 7, 2017**. All questions should be submitted electronically via e-mail to: bcope@scppa.org, referencing **Energy Storage RFI Questions** in the subject line. Answers to all questions will be provided to inquisitor via e-mail within 4 business days from the date received. Answers to questions that SCPPA, at its sole determination and discretion, deems

to be substantive or that would place the inquisitor at a distinct and unfair advantage to other potential Respondents will be posted on SCPPA's website at:
http://www.scppa.org/pages/misc/RFIs.html within 1 business days from the date delivered to inquisitor, but no later than **March 12, 2017**. It is the responsibility of potential Respondents to review this website for any and all postings.

IV. Information Submission Required Elements

1. **Transmittal Letter Content:**
   - **a)** A brief statement of the Respondent's understanding of the services and products being requested and considered, as well as any physical or legal limitations or constraints that may exist in allowing the Respondent to provide such service and/or products.
   - **b)** Legal name of Individual or Firm (Respondent) with physical street address, telephone and FAX numbers with the name(s), respective position(s)/title(s) and e-mail address(es) of all individuals authorized to represent the Respondent.

2. **Information Statement to describe your firm's:**
   - **a)** experience in performing or providing the services and products within Areas of Interest as referenced above and as may be applicable to this RFI;
   - **b)** organizational structure, management Information, and other service or product related Information, including number of years firm or individual has been in the related business;
   - **c)** list or table of key employees including a description of their Information, experience and duties related to the services and/or products referenced within this RFI;
   - **d)** a list of office locations where work will be performed, if different than the physical address referenced above;
   - **e)** reliance on or use of subcontractors to perform services or develop[p projects referenced within this RFI; and
   - **f)** describe whether the Respondent has, within the last five years, rendered any service to SCPPA or to any of SCPPA's Members, either as a contractor or subcontractor, either under the name presented in the Transmittal letter or any other name or organization. If so, please provide details (status as prime or subcontractor, brief description of the contract, contract start and end dates, the contract administrator name, and total actual contract expenditures).
   - **g)** If the Respondent has not rendered any service within the last five years to SCPPA or to any of SCPPA's Members, then please provide as many as five (5) references of similar or related work performed within the past 3 years with the requested details described above including the counterparty for which services were provided.
   - **h)** Respondent shall indicate any and all pending litigation that could affect the viability of Respondent's submittal, continuance of existing contracts, operation or financial stability.

V. Information Submission Delivery Requirements

One (1) electronic copy of your submittal should be delivered no later than 4:00 pm PST on March 30, 2017 e-mailed to: bcope@scppa.org with Subject/Title as: **[Respondent Name] Energy Storage RFI Submittal**.

One (1) hard copy of your submittal can or may also be delivered to the address below no later than the time and date referenced above, but hard-copy submittal is not required.

Southern California Public Power Authority
Energy Storage RFI
Attention: Bryan Cope
1160 Nicole Court
Glendora, California 91740

No contact should be made with the Board of Directors, any committee or working group representatives, or SCPPA Participating Members concerning this RFI.

All information received by SCPPA in response to this RFI is subject to the California Public Records Act and may be subject to the California Brown Act and all submissions may be subject to review in the event of an audit.

VI. Submittal Terms and Conditions

1. SCPPA reserves the right to cancel this RFI at any time, reject any and all submittals and to waive irregularities.

2. SCPPA shall determine at its sole discretion the value of any and/or all submittals.

3. Submittals may be sub-divided or combined with other submittals, at SCPPA's sole discretion.

4. SCPPA shall perform an initial screening and evaluation to identify and eliminate any submittals that are not responsive to the request for Information, do not meet the minimum requirements set forth in the request for Information or are otherwise deemed, at SCPPA's sole discretion, unable to provide dependable and reliable services.

5. SCPPA reserves the right to submit supplementary follow-up questions or inquiries to request clarification of information submitted and to request additional information from any one or more of the Respondents.

6. SCPPA reserves the right, without qualification and in its sole discretion, to accept or reject any or all submittals for any reason without explanation to the Respondent, or to subsequently make an award to one or more Respondent(s), who, in the opinion of SCPPA, will provide valued service and/or products to SCPPA and its Members.

7. SCPPA may decline to enter into any potential engagement agreement or contract with any Respondent, terminate negotiations with any Respondent, or to abandon the RFI process in its entirety.

8. Those Respondents who provide Qualification submittals agree to do so without legal recourse against SCPPA, its Members, their directors, officers, employees and agents for rejection of their submittal(s) or for failure to execute or act on their submittal for any reason.

9. SCPPA shall not be liable to any Respondent or party in law or equity for any reason whatsoever for any acts or omissions arising out of or in connection with this request for submittals.

10. SCPPA shall not be liable for any costs incurred by any Respondents in preparing any information for submission in connection with this RFI process or any and all costs resulting from responding to this RFI. Any and all such costs whatsoever shall remain the sole responsibility of the Respondent.

11. SCPPA may require certain performance assurances from Respondents prior to entering into negotiations for a proposed project. Such assurances may potentially include a requirement that Respondents provide some form of performance security.

12. Either SCPPA collectively or Members individually may respond to, or enter into negotiations for services related to a submittal. SCPPA is not responsible or liable for individual Members interactions with the Respondent which are not entirely conducted through SCPPA or at SCPPA's option or election to engage the Respondent as defined within the Terms and Conditions herein.

13. Submission of a submittal constitutes acknowledgement that the Respondent has read and agrees to be bound by the terms and specifications of this RFI and any addenda subsequently issued prior to the due date for a submittal.

14. Information in this RFI is accurate to the best of SCPPA's knowledge but is not guaranteed to be correct. Respondents are expected to complete all of their due diligence activities prior to entering into any final contract negotiations with SCPPA.

15. SCPPA reserves the right to reject any submittal for any reason without cause. SCPPA reserves the right to enter into relationships with more than one Respondent, can choose not to proceed with any Respondent with respect to one or more categories of services, and can choose to suspend this RFI or to issue a new RFI that would supersede and replace this RFI.

Additional Considerations for Submittal

1. **Response Preparations:** Submittals should be prepared simply and economically, without the inclusion of unnecessary promotional materials. Information should be submitted on recycled paper that has a minimum of thirty percent (30%) post-consumer recycled content and duplex copied (double-sided pages) where possible and applicable.

2. **Insurance, Licensing, or other Certification:** If selected subsequently to provide service(s) and/or product(s) related to the Areas of Interest in this RFI, the Respondent and each of its known subcontractors will be required to maintain sufficient insurance, licenses, or other required certifications for the type of work being performed. SCPPA or its Members may require specific insurance coverage to be established and maintained during the course of work and as a condition of award or continuation of contract.

3. **Non-Discrimination/Equal Employment Practices/Affirmative Action Plan:** If selected subsequently to provide service(s) and/or product(s) related to the Areas of Interest in this RFI, the Respondent and each of its known subcontractors may be required to complete and file an acceptable

Affirmative Action Plan. The Affirmative Action Plan may be set forth in the form required as a business practice by the Department of Water and Power of the City of Los Angeles, SCPPA's largest Member.

4. **Living Wage Ordinance:** If selected subsequently to provide service(s) and/or product(s) related to the Areas of Interest in this RFI, the Respondent may be required to comply with the applicable provisions of the City of Los Angles Living Wage Ordinance and the City of Los Angeles Service Contract Workers Retention Ordinance. The Living Wage Ordinance provisions are found in Section 10.36 of the Los Angeles City Administrative Code; and the Service Contract Workers Retention Ordinance are found in Section 10.37 of the Los Angeles Administrative Code.

5. **Prevailing Wage Rates:** If selected, the Respondent will be required to conform to prevailing wage rates applicable to the location(s) where any work is being performed. Workers shall be paid not less than prevailing wages pursuant to determinations of the Director of Industrial Relations as applicable in accordance with the California Labor Code. To access the most current information on effective determination rates, Respondent shall contact:

   Department of Industrial Relations
   Division of Labor Statistics and Research
   PO Box 420603, San Francisco, CA 94142-0603
   Division Office Telephone: (415) 703-4780
   Prevailing Wage Unit Telephone: (415) 703-4774
   Web: http://www.dir.ca.gov/dlsr/DPreWageDetermination.htm

6. **Child Support Policy:** If selected subsequently to provide service(s) and/or product(s) related to the Areas of Interest in this RFI, the Respondent may be required to comply with the City of Los Angeles Ordinance No. 172401, which requires all contractors and subcontractors performing work to comply with all reporting requirements and wage earning assignments and wage earning assignments relative to court ordered child support.

7. **Supplier Diversity:** Respondents shall take reasonable steps to ensure that all available business enterprises, including Small Business Enterprises (SBEs), Disadvantaged Business Enterprises (DBEs), Women-Owned Business Enterprises (WBEs), Minority-Owned Business Enterprises (MBEs), Disabled Veteran Business Enterprises (DVBEs), and other Business Enterprises (OBEs), have an equal opportunity to compete for and participate in the work being requested by this RFI. Efforts to obtain participation of these business enterprises may reasonably be expected to produce a twenty-five percent (25%) participation goal for SBEs. For the purpose of this RFI, SCPPA's Supplier Diversity program is modeled after that of the Los Angeles Department of Water and Power. Further information concerning the Supplier Diversity Program may be obtained from the Supply Chain Services Division of the Los Angeles Department of Water and Power.