LAZARD'S LEVELIZED COST OF STORAGE ANALYSIS—VERSION 7.0

LAZARD

Table of Contents

I	INTRODUCTION	1
II	LAZARD'S LEVELIZED COST OF STORAGE ANALYSIS V7.0	3
III	ENERGY STORAGE VALUE SNAPSHOT ANALYSIS	7
IV	PRELIMINARY VIEWS ON LONG-DURATION STORAGE	11
	APPENDIX	
A	Supplemental LCOS Analysis Materials	14
B	Value Snapshot Case Studies	16
1	Value Snapshot Case Studies—U.S.	17
2	Value Snapshot Case Studies—International	23

I Introduction

Introduction

Lazard's Levelized Cost of Storage ("LCOS") analysis[(1)] addresses the following topics:

- **Introduction**
  - A summary of key findings from Lazard's LCOS v7.0
- **Lazard's LCOS analysis**
  - Overview of the operational parameters of selected energy storage systems for each use case analyzed
  - Comparative LCOS analysis for various energy storage systems on a $/kW-year and $/MWh basis
- **Energy Storage Value Snapshot analysis**
  - Overview of the Value Snapshot analysis and identification of selected geographies for each use case analyzed
  - Summary results from the Value Snapshot analysis
- **A preliminary view of long-duration storage technologies**
- **Selected appendix materials**
  - Supplementary materials for Lazard's LCOS analysis, including methodology and key assumptions employed
  - Supporting materials for the Value Snapshot analysis, including pro forma results for the U.S. and International Value Snapshot case studies

Source: Lazard and Roland Berger.
(1) Lazard's LCOS analysis is conducted with support from Enovation Analytics and Roland Berger.

Summary of Key Findings and Observed Trends in the Energy Storage Industry

Technology	• Concerns regarding the availability of Lithium-ion battery modules are increasing given ongoing supply constraints – Supply constraints in commodity markets and manufacturing activities have led end-users to more seriously consider Tier 2 and Tier 3 suppliers – Stationary storage applications are increasingly competing with EVs over module supply as automobile manufacturers continue to shift product offerings away from traditional gasoline- and diesel-fueled vehicles • Module demand from EVs is expect to increase to ~90% from ~75% of end-market demand by 2030. Stationary storage currently represents <5% of end market demand and is not expected to exceed 10% of the market by 2030 • Pressure on legacy integrators continues to build as the industry matures – Battery OEMs are moving downstream in an effort to capture more margin and expand market share, offering fully wrapped DC blocks, i.e., storage modules, container, supporting controls, fire suppression and associated cabling – Concurrently, some developers are expanding in-house engineering, procurement and construction activities – Legacy integrators are moving into energy management software, with many acquiring distributed energy resource management platforms • Market preference has shifted significantly towards Lithium Iron Phosphate ("LFP") vs. Nickel Manganese Cobalt ("NMC") chemistries – Industry participants increasingly prefer LFP chemistries given perceived fire safety, cost and operational advantages (e.g., depth of discharge). The cost advantage of LFP chemistries tends to be more pronounced in shorter-duration applications • Interest in longer-duration technologies continues to grow in tandem with expectations of ever greater penetration of renewable energy generation – Adoption, however, remains limited given a lack of required technology and duration-specific price signals in wholesale markets (e.g. capacity)
Use Cases	• Hybrid applications are becoming more valuable and, by extension, widespread as grid operators begin adopting Estimated Load Carry Capability ("ELCC") methodologies to value resources – Adoption of ELCC methodologies is driving increasing deployment of hybrid resources (e.g., storage paired with solar) to mitigate resource intermittency. Storage co-located with solar is expected to be most attractive in the U.S. Midwest, including in the Southwest Power Pool ("SPP") region – In ERCOT, for example, hybrid assets account for ~35% of storage MW in the current interconnection queue (i.e., ~29% solar, ~1% wind and ~5% other) • Developers are increasingly targeting markets in the Western U.S. (California), Western Europe and South America for long duration storage projects as these areas experience ever greater penetration of intermittent renewable energy generation in tandem with declining dispatchable conventional generation capacity

Source: LCOS surveys, Roland Berger.

II Lazard's Levelized Cost of Storage Analysis v7.0

Energy Storage Use Cases—Overview

By identifying and evaluating the most commonly deployed energy storage applications, Lazard's LCOS analyzes the cost and value of energy storage use cases on the grid and behind-the-meter

		Use Case Description	Technologies Assessed
In-Front-of-the-Meter	1 Wholesale	• Large-scale energy storage system designed for rapid start and precise following of dispatch signal. Variations in system discharge duration are designed to meet varying system needs (i.e., short-duration frequency regulation, longer-duration energy arbitrage[1] or capacity, etc.) – To better reflect current market trends, this report analyzes one-, two- and four-hour durations[2]	• Lithium Iron Phosphate • Lithium Nickel Manganese Cobalt Oxide • Flow Battery—Vanadium • Flow Battery—Zinc Bromine
In-Front-of-the-Meter	2 Transmission and Distribution	• Energy storage system designed to defer or avoid transmission and/or distribution upgrades, typically placed at substations or distribution feeders controlled by utilities to provide flexible capacity while also maintaining grid stability	• Lithium Iron Phosphate • Lithium Nickel Manganese Cobalt Oxide • Flow Battery—Vanadium • Flow Battery—Zinc Bromine
In-Front-of-the-Meter	3 Wholesale (PV+Storage)	• Energy storage system designed to be paired with large solar PV facilities to better align timing of PV generation with system demand, reduce solar curtailment and provide grid support	• Lithium Iron Phosphate • Lithium Nickel Manganese Cobalt Oxide • Flow Battery—Vanadium • Flow Battery—Zinc Bromine
Behind-the-Meter	4 Commercial & Industrial (Standalone)	• Energy storage system designed for behind-the-meter peak shaving and demand charge reduction for C&I energy users – Units often configured to support multiple commercial energy management strategies and provide optionality for the system to provide grid services to a utility or the wholesale market, as appropriate in a given region	• Lithium Iron Phosphate • Lithium Nickel Manganese Cobalt Oxide • Flow Battery—Vanadium • Flow Battery—Zinc Bromine
Behind-the-Meter	5 Commercial & Industrial (PV+Storage)	• Energy storage system designed for behind-the-meter peak shaving and demand charge reduction services for C&I energy users – Systems designed to maximize the value of the solar PV system by optimizing available revenue streams and subsidies	• Lithium Iron Phosphate • Lithium Nickel Manganese Cobalt Oxide • Flow Battery—Vanadium • Flow Battery—Zinc Bromine
Behind-the-Meter	6 Residential (PV+Storage)	• Energy storage system designed for behind-the-meter residential home use—provides backup power, power quality improvements and extends usefulness of self-generation (e.g., PV+storage) – Regulates the power supply and smooths the quantity of electricity sold back to the grid from distributed PV applications	• Lithium Iron Phosphate • Lithium Nickel Manganese Cobalt Oxide

Source: Industry interviews, Lazard and Roland Berger.

Note: Use case numbering shown above serves as an identifier for the corresponding individual use cases discussed on subsequent pages.

(1) For the purposes of this analysis, "energy arbitrage" in the context of storage systems paired with solar PV includes revenue streams associated with the sale of excess generation from the solar PV system, as appropriate, for a given use case.

(2) The Value Snapshot analysis only evaluates the four-hour wholesale use case.

Energy Storage Use Cases—Illustrative Operational Parameters

Lazard's LCOS evaluates six commonly deployed use cases for energy storage by identifying illustrative operational parameters[1]

- **Energy storage systems may also be configured to support combined/"stacked" use cases**

= "Usable Energy"[2] (dashed outline: columns D, G and H)

D = B x C; G = D x E x F; H = A x G

		A Project Life (Years)	B Storage (MW)[3]	Solar PV (MW)	Battery Degradation (per annum)	C Storage Duration (Hours)	D Nameplate Capacity (MWh)[4]	E 90% DOD Cycles/ Day[5]	F Days/ Year[6]	G Annual MWh	H Project MWh
In-Front-of-the-Meter	1 Wholesale[7]	20	100	--	2.6%	1	100	1	350	31,500	630,000
		20	100	--	2.6%	2	200	1	350	63,000	1,260,000
		20	100	--	2.6%	4	400	1	350	126,000	2,520,000
	2 Transmission and Distribution[7]	20	10	--	1.5%	6	60	1	25	1,350	27,000
	3 Wholesale (PV+Storage)[7]	20	50	100	2.6%	4	200	1	350	63,000	1,260,000
Behind-the-Meter	4 Commercial & Industrial (Standalone)	10	1	--	2.6%	2	2	1	250	450	4,500
	5 Commercial & Industrial (PV+Storage)[7]	20	0.50	1	2.3%	4	2	1	350	630	12,600
	6 Residential (PV+Storage)	20	0.006	0.010	1.9%	4	0.025	1	350	8	158

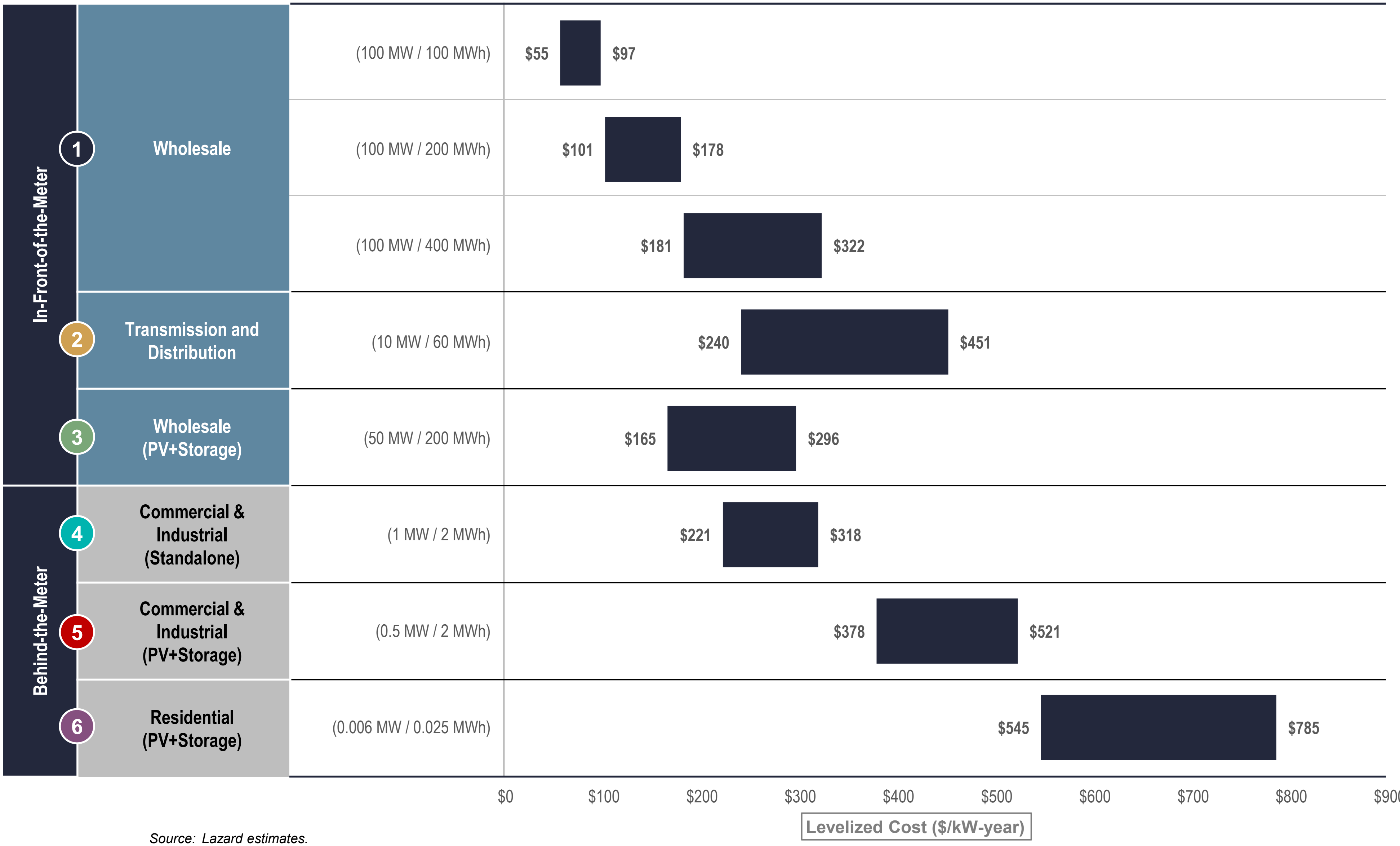
Source: Lazard and Roland Berger.

Note: Operational parameters presented are applied to Value Snapshots and LCOS calculations. Annual and Project MWh presented are illustrative. Annual battery output in the Value Snapshot analysis depends on a participation optimization analysis and may vary from the representative project MWh by use case.

(1) The six use cases below represent illustrative current and contemplated energy storage applications and are derived from Industry survey data.
(2) Usable energy indicates energy stored and available to be dispatched from the battery.
(3) Indicates power rating of system (i.e., system size).
(4) Indicates total battery energy content on a single, 100% charge, or "usable energy." Usable energy divided by power rating (in MW) reflects hourly duration of system. This analysis reflects common practice in the market whereby batteries are upsized in year one to 110% of nameplate capacity (e.g., a 100 MWh battery actually begins project life with 110 MWh).
(5) "DOD" denotes depth of battery discharge (i.e., the percent of the battery's energy content that is discharged). Depth of discharge of 90% indicates that a fully charged battery discharges 90% of its energy. To preserve battery longevity, this analysis assumes that the battery never charges over 95%, or discharges below 5%, of its usable energy.
(6) Indicates number of days of system operation per calendar year.
(7) Augmented to nameplate MWh capacity in year 11 of operation.

Unsubsidized Levelized Cost of Storage Comparison—Capacity ($/kW-year)

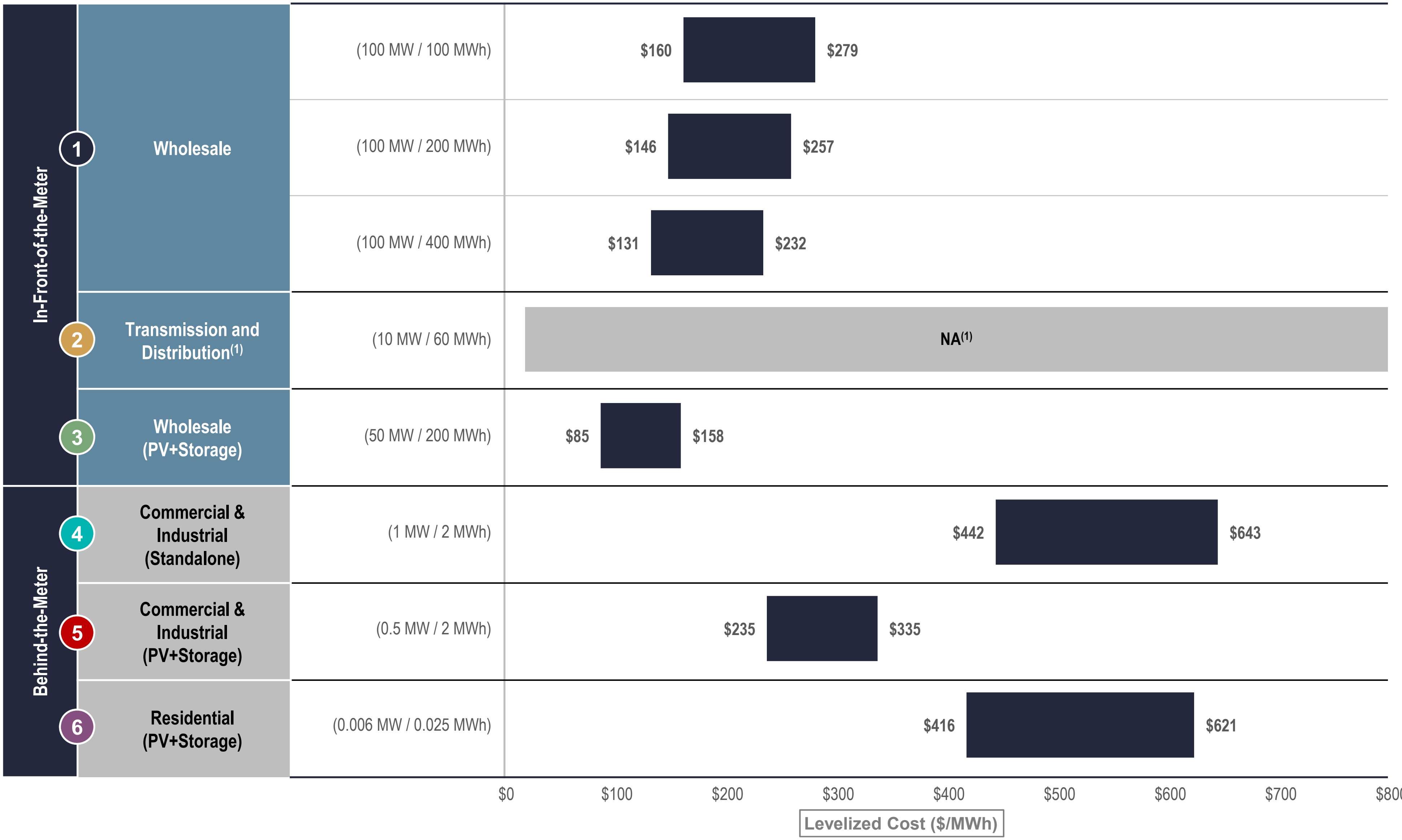
Lazard's LCOS analysis evaluates storage systems on a levelized basis to derive cost metrics based on nameplate capacity



Source: *Lazard estimates.*
Note: Here and throughout this presentation, unless otherwise indicated, analysis assumes a capital structure consisting of 20% debt at an 8% interest rate and 80% equity at a 12% cost of equity. Capital costs are composed of the storage module, balance-of-system and power conversion equipment, collectively referred to as the Energy Storage System ("ESS"), solar equipment (where applicable) and EPC. Augmentation costs are included as part of O&M expenses in this analysis and vary across use cases due to usage profiles and lifespans.

Unsubsidized Levelized Cost of Storage Comparison—Energy ($/MWh)

Lazard's LCOS analysis evaluates storage systems on a levelized basis to derive cost metrics based on annual energy output



Source: Lazard estimates.

(1) Given the operational parameters for the Transmission and Distribution use case (i.e., 25 cycles per year), certain levelized metrics are not comparable between this and other use cases presented in Lazard's Levelized Cost of Storage report. The corresponding levelized cost of storage for this case would be $1,613/MWh – $3,034/MWh.

III Energy Storage Value Snapshot Analysis

Revenue Potential for Relevant Use Cases

Numerous potential sources of revenue available to energy storage systems reflect the benefits provided to customers and the grid

- **The scope of revenue sources is limited to those captured by existing or soon-to-be commissioned projects. Revenue sources that are not identifiable or without publicly available data are not analyzed**

			Use Cases(1)					
		Description	Wholesale	Transmission & Distribution	Wholesale (PV + S)	Commercial (Standalone)	Commercial (PV + S)	Residential (PV + S)
Wholesale	Demand Response—Wholesale	• Manages high wholesale price or emergency conditions on the grid by calling on users to reduce or shift electricity demand				✓	✓	✓
Wholesale	Energy Arbitrage	• Storage of inexpensive electricity to sell later at higher prices (only evaluated in the context of a wholesale market)	✓	✓	✓			
Wholesale	Frequency Regulation	• Provides immediate (four-second) power to maintain generation-load balance and prevent frequency fluctuations	✓	✓	✓	✓	✓	
Wholesale	Resource Adequacy	• Provides capacity to meet generation requirements at peak loading	✓	✓	✓	✓	✓	
Wholesale	Spinning/ Non-Spinning Reserves	• Maintains electricity output during unexpected contingency events (e.g., outages) immediately (spinning reserve) or within a short period of time (non-spinning reserve)	✓	✓	✓	✓	✓	
Utility	Distribution Deferral	• Provides extra capacity to meet projected load growth for the purpose of delaying, reducing or avoiding distribution system investment		✓				
Utility	Transmission Deferral	• Provides extra capacity to meet projected load growth for the purpose of delaying, reducing or avoiding transmission system investment		✓				
Utility	Demand Response—Utility	• Allows users to reduce or shift electricity demand in response to high wholesale pricing or emergency conditions on the grid				✓	✓	✓
Customer	Bill Management	• Allows reduction of demand charge using battery discharge and the daily storage of electricity for use when time-of-use rates are highest				✓	✓	✓
Customer	Backup Power	• Provides backup power for use by Residential and Commercial customers during grid outages				✓	✓	✓

Source: Lazard and Roland Berger.
(1) Represents the universe of potential revenue streams available to the various use cases. Does not necessarily represent revenue streams analyzed in the Value Snapshots.

Value Snapshot Case Studies—Overview

Lazard's Value Snapshots analyze the financial viability of illustrative energy storage systems designed for selected use cases from a returns perspective

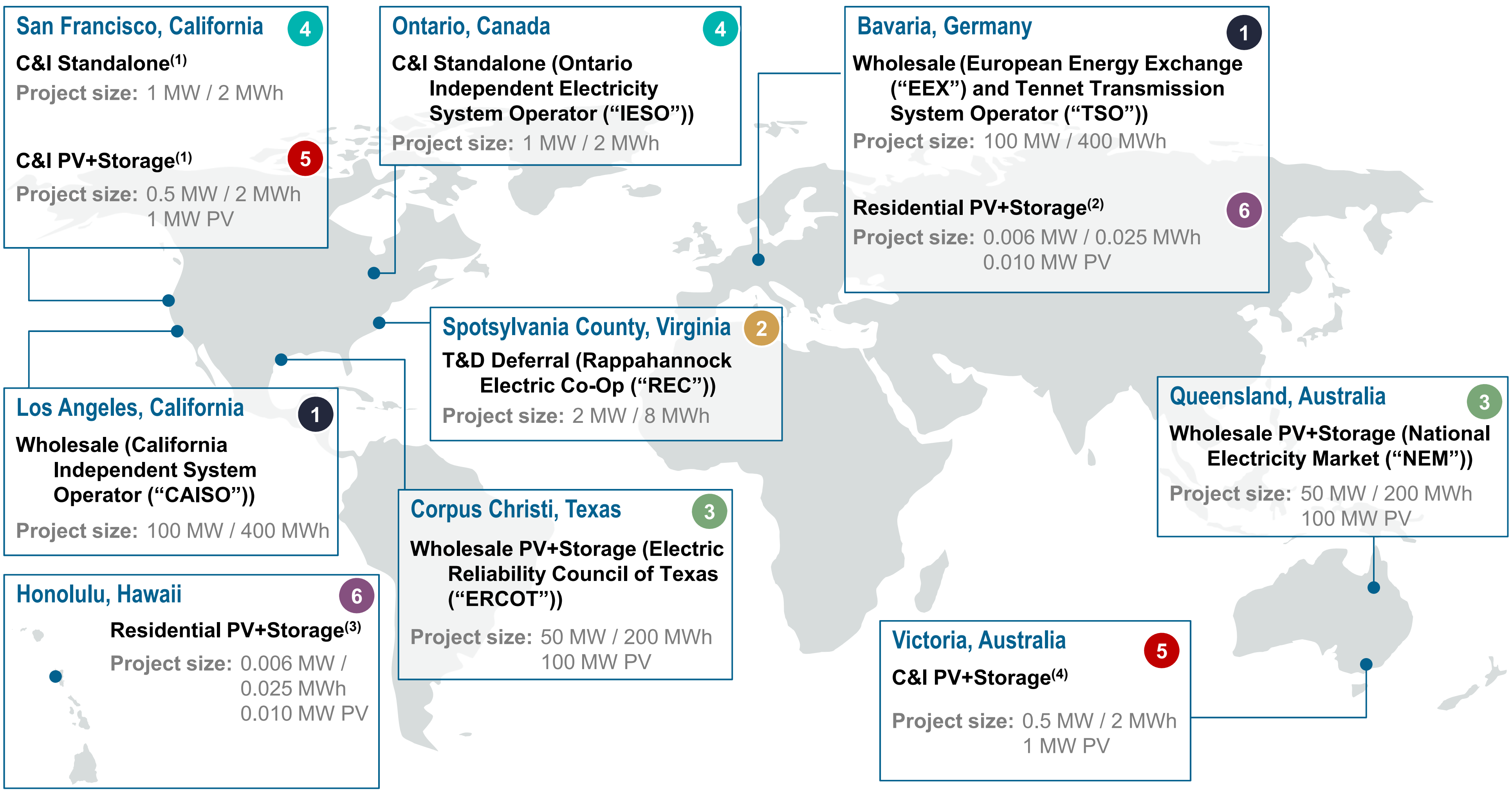
- **The geographic locations, assumed installed and operating costs, and associated revenue streams reflect current energy storage market activity**

Use Case	U.S. Location	International Location	Owner	Revenue Streams
1 Wholesale	CAISO (SP-15)	Germany	• IPP in a competitive wholesale market	• Wholesale market settlement • Local capacity resource programs
2 Transmission and Distribution	REC (Virginia)	--(1)	• Wires utility in a competitive wholesale market	• Capital recovery in regulated rates, avoided cost to wires utility and avoided cost incentives
3 Wholesale (PV+Storage)	ERCOT (South Texas)	Australia	• IPP in a competitive wholesale market	• Wholesale market settlement
4 Commercial & Industrial (Standalone)	CAISO (San Francisco)	Canada	• Customer or financier	• Tariff settlement, DR participation, avoided costs to commercial customer, local capacity resource programs and incentives
5 Commercial & Industrial (PV+Storage)	CAISO (San Francisco)	Australia	• Customer or financier	• Tariff settlement, DR participation, avoided costs to commercial customer, local capacity resource programs and incentives
6 Residential (PV+Storage)	HECO (Hawaii)	Germany	• Customer or financier	• Tariff settlement, avoided costs to residential customer and incentives

Source: Lazard and Roland Berger.
Note: Actual project returns may vary due to differences in location-specific costs, revenue streams and owner/developer risk preferences.
(1) Lazard's Value Snapshot analysis intentionally excluded a Transmission and Distribution use case from its international analysis given the lack of substantive publicly available data for projects deployed for this use case.

Value Snapshot Case Studies—Overview (cont'd)

Lazard's Value Snapshots analyze use cases across various global geographies



San Francisco, California

4 **C&I Standalone**[(1)]
Project size: 1 MW / 2 MWh

5 **C&I PV+Storage**[(1)]
Project size: 0.5 MW / 2 MWh
1 MW PV

Ontario, Canada

4 **C&I Standalone (Ontario Independent Electricity System Operator ("IESO"))**
Project size: 1 MW / 2 MWh

Bavaria, Germany

1 **Wholesale (European Energy Exchange ("EEX") and Tennet Transmission System Operator ("TSO"))**
Project size: 100 MW / 400 MWh

6 **Residential PV+Storage**[(2)]
Project size: 0.006 MW / 0.025 MWh
0.010 MW PV

Spotsylvania County, Virginia

2 **T&D Deferral (Rappahannock Electric Co-Op ("REC"))**
Project size: 2 MW / 8 MWh

Los Angeles, California

1 **Wholesale (California Independent System Operator ("CAISO"))**
Project size: 100 MW / 400 MWh

Corpus Christi, Texas

3 **Wholesale PV+Storage (Electric Reliability Council of Texas ("ERCOT"))**
Project size: 50 MW / 200 MWh
100 MW PV

Queensland, Australia

3 **Wholesale PV+Storage (National Electricity Market ("NEM"))**
Project size: 50 MW / 200 MWh
100 MW PV

Honolulu, Hawaii

6 **Residential PV+Storage**[(3)]
Project size: 0.006 MW /
0.025 MWh
0.010 MW PV

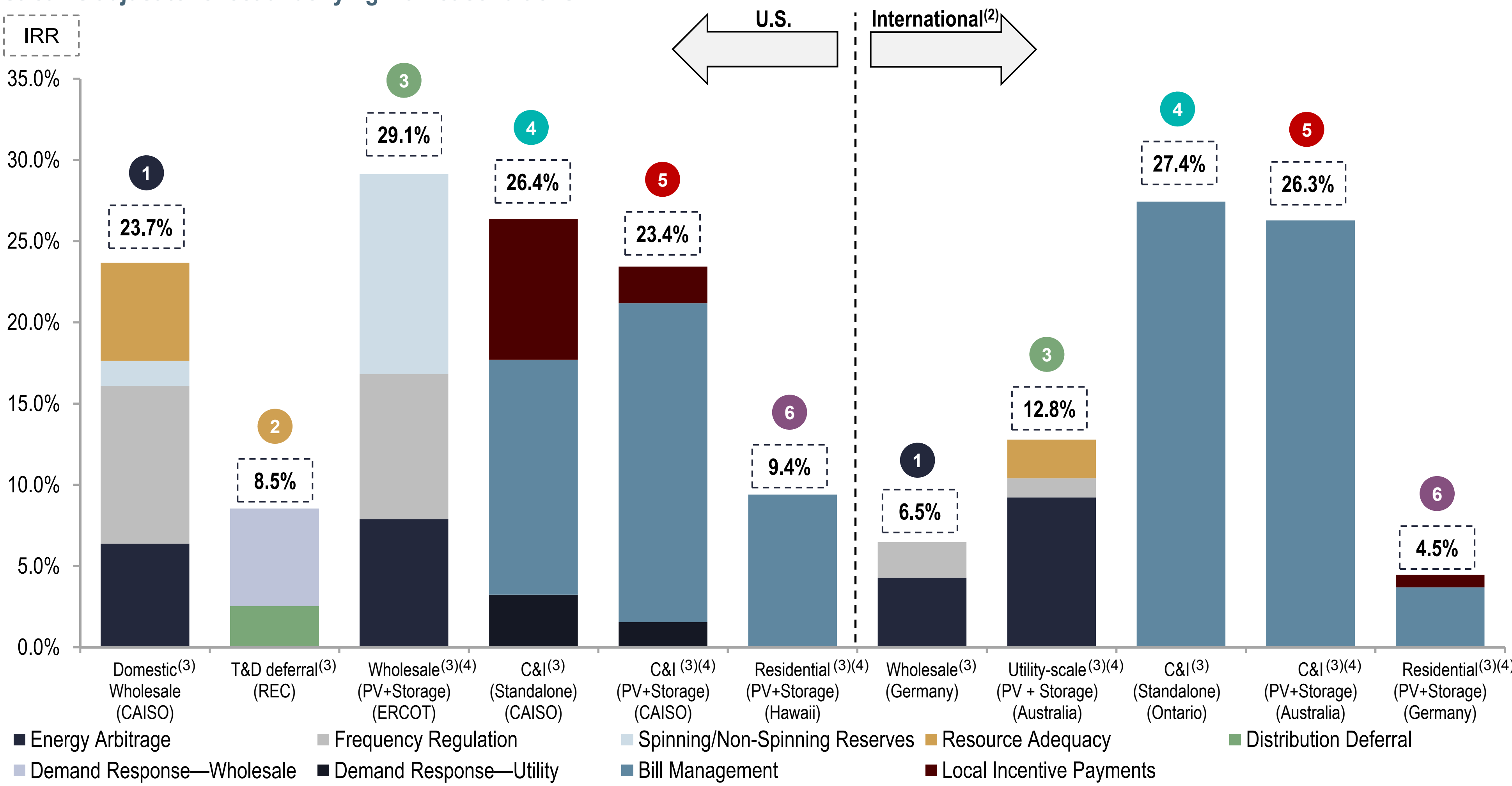
Victoria, Australia

5 **C&I PV+Storage**[(4)]
Project size: 0.5 MW / 2 MWh
1 MW PV

Source: Lazard and Roland Berger.
Note: Project parameters (i.e., battery size, duration, etc.) presented above correspond to the inputs used in the LCOS analysis. For the T&D deferral use case, the parameters for the case study are unique to the observed project.
(1) Assumes the project provides services under contract with the Pacific Gas and Electric Company ("PG&E").
(2) Assumes the project provides services under contract with Stadtwerke Munich ("SWM").
(3) Assumes the project provides services under contract with the Hawaiian Electric Company ("HECO").
(4) Assumes the project provides services under contract with AusNet Services.

Value Snapshot Case Studies—Summary Results[1]

Project economics evaluated in the Value Snapshot analysis continue to evolve year-over-year as costs improve and available revenue streams adjust to reflect underlying market conditions



Source: Industry interviews, Enovation Analytics, Lazard and Roland Berger.

Note: All figures presented in USD using the following exchange rates: USD 0.69/AUD, USD 0.75/CAD and USD 1.14/EUR.

(1) Cost structure representative of the "Average Case" is used in the IRR analysis.

(2) Lazard's Value Snapshot analysis intentionally excluded a Transmission and Distribution use case from its international analysis given the lack of substantive publicly available data for projects deployed for this use case.

(3) Revenues for Value Snapshots use cases 1 – 3 are based on wholesale prices from the 12 months prior to the onset of the COVID-19 pandemic (i.e., February 2019 – February 2020) in order to normalize the underlying data. Revenues for Value Snapshots use cases 4 – 6 are based on the most recent tariffs, programs and incentives available as of 1H 2021.

(4) While it is common to model storage and solar separately, this analysis models both as a combined system for consistency with prior LCOS reports.

IV Preliminary Views on Long-Duration Storage

Selected Long Duration Storage Technologies—Overview

A variety of long-duration energy storage technologies are in various stages of development and commercial viability

	Flow	Thermal	Mechanical
Typical Technologies	• Zinc Bromine • Vanadium	• Latent Heat • Sensible Heat	• Gravity Energy Storage • Compressed Air Energy Storage ("CAES")
Description	• Energy storage systems generating electrical energy from chemical reactions, often stored in liquid tanks	• Solutions storing thermal energy by heating or cooling a storage medium	• Solutions that store energy as a kinetic, gravitational potential or compression medium
Advantages	• Minimal degradation from cycling • Modular options available • Relatively few safety concerns	• Able to leverage mature industrial cryogenic technology base • Materials are generally inexpensive • Power and energy capacity are independently scalable	• Mechanical is proven via established technologies (e.g., pumped hydro) • Attractive economics • Limited safety concerns
Disadvantages	• Lower energy density and round-trip efficiency • Relatively higher O&M costs • Lacks adjacent industry to scale production • High-cost materials (e.g., vanadium) • Limited track record at larger, commercial scale	• Lower energy density vs. competing technologies • Challenging to increase capacity in modular increments after installation • Operating performance is sensitive to local climatic conditions • Limited track record at larger scale	• Lower round-trip efficiency (e.g., CAES systems) • Potential for substantial physical footprint vs. competing technologies • Generally difficult to modularize

Source: Cleantech Group, Desk research, Lazard and Roland Berger.

Market Activity Observed in Long-Duration Storage

As regional grids achieve higher penetration of renewable energy generation, long-duration storage is well positioned to take advantage of the corresponding increase in the potential for curtailed and low-price generation

Market Context

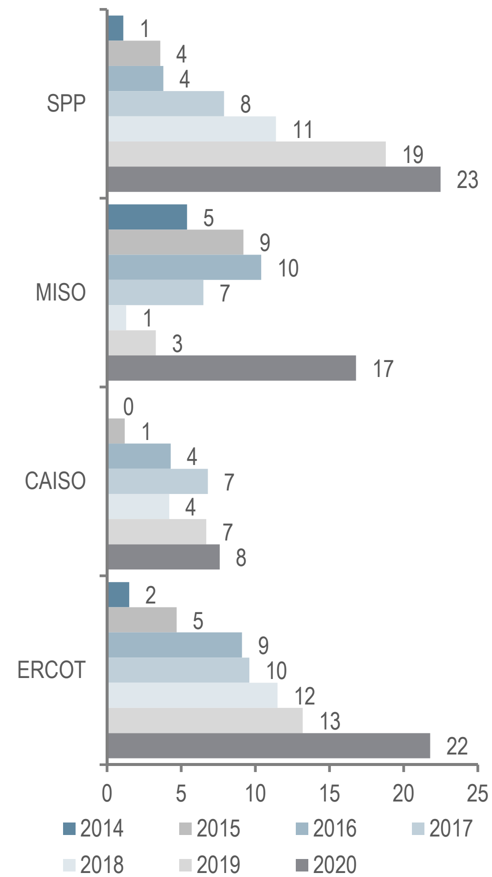
- Lithium-ion technology has proven to be a viable short-duration application, but it is rarely cost-effective past six hours given the cost structure of incremental units of duration
- Increased renewable generation enhances the value of energy arbitrage and reliability services, while climate adaptation drives demand for grid resilience
  - Long-duration storage (i.e., >6 hours) is better suited to addressing both of these grid conditions
- California regulators have stated that the state will need 1 GW of long-duration storage by 2026. Subsequent to this announcement, a coalition of eight community-choice aggregators published a request for proposals seeking 500 MWs of long-duration storage capacity
- Increasing occurrences of low or negative pricing have been observed across various energy markets, corresponding to rising levels of renewable penetration and a greater number of curtailment events
  - Incremental storage, transmission capacity and further interconnection between regional grids can reduce curtailment levels as renewable energy generation continues to increase

Recent Project Activity

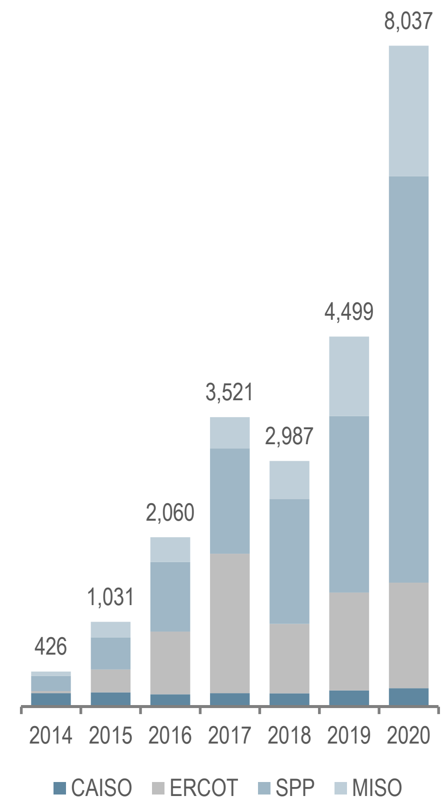
- **Flow:** SDG&E and Sumitomo Electric have partnered to install a 2 MW / 8 MWh vanadium redox flow battery in California
- **Thermal:** Vantaa Energy intends to deploy 90 GWh of thermal storage in Finland in 2022
- **Mechanical:** Hydrostor has proposed a 200 MW / 1,600 MWh CAES project in New South Wales, Australia
- **Other:** Form Energy and Great River Energy have partnered to install a 1 MW / 250 MWh aqueous air battery in Minnesota with a target in-service date of 2023

Grid Impacts of Increasing Renewable Energy Penetration

Selected ISO negative pricing behavior, 2014 – 2020
(% of hours <$10/MWh)



Selected ISO curtailments, 2014 – 2020 (GWh)



Source: Greentech Media, the California Public Utility Commission, CleanTech Group, Industry interviews, Lazard and Roland Berger.

Illustrative Long-Duration Use Case(1)

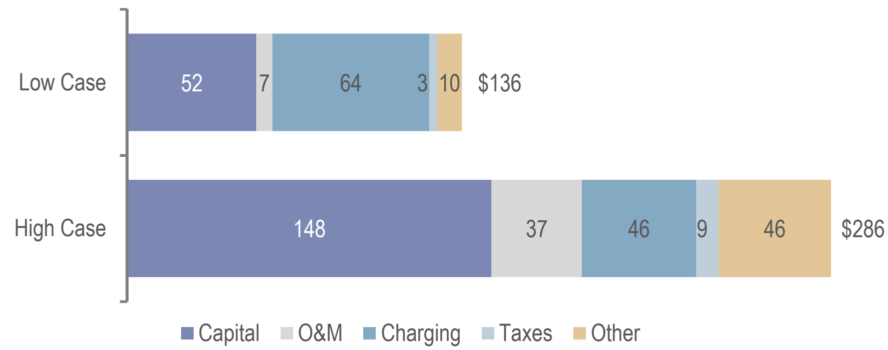
A levelized cost of storage analysis of an illustrative 100 MW / 1,000 MWh energy storage system yields potentially attractive economics relative to the available alternatives

Use Case Commentary

- Utility companies and corporates are focused on the potential of long-duration energy storage technologies to help achieve emissions-reduction targets
- Long-duration storage developers and OEMs are targeting areas with curtailed renewable energy generation, such as those with abundant onshore or offshore wind, which are also transmission constrained
- The mining sector also represents an attractive opportunity where long-duration storage may be a cost-effective alternative to diesel-fired reciprocating engines
- Key observations on traditional battery technologies vs. long-duration technologies:
  - Short-duration storage technologies (e.g., Lithium-ion) maintain relatively higher exposure to expensive, volatile commodities as production inputs. Current long-duration technologies do not have such exposure and anticipate limited remediation or recycling costs
  - Long-duration storage technologies typically have lower round-trip efficiencies than short-duration technologies have and, by extension, incur higher charging costs
  - Many long-duration storage technologies are large capital assets that are challenging to size in modular increments, whereas short-duration technologies can be scaled incrementally

LCOS—100 MW / 1,000 MWh Battery

Energy ($/MWh)



Capacity ($/kW-year)

Key Assumptions

- Standalone battery, 20-year project life
- 1 full battery cycle, 350 cycles/day
- No degradation or augmentation costs
- Average domestic charging costs and associated escalation

Source: *Industry interviews, EIA, Lazard and Roland Berger.*

(1) Energy storage technologies assessed: flow (e.g. Vanadium and Zinc Bromine), thermal and mechanical (i.e., compressed and liquefied air energy storage). Due to the limited deployment of these projects to date, and corresponding lack of operating data, assumptions utilized in this analysis are preliminary.

Appendix

A Supplemental LCOS Analysis Materials

Levelized Cost of Storage Analysis—Methodology

Our Levelized Cost of Storage analysis consists of creating an energy storage model representing an illustrative project for each relevant technology and solving for the $/MWh figure that results in a levered IRR equal to the assumed cost of equity

Wholesale (100 MW / 200 MWh)—Low Case Sample Calculations

Year [1]		0	1	2	3	4	5	20
Capacity (MW)	(A)		100	100	100	100	100	100
Available Capacity (MW)			110	107	104	102	99	79
Total Generation ('000 MWh) [2]	(B)*		69	68	66	64	62	50
Levelized Storage Cost ($/MWh)	***(C)***		***$146***	***$146***	***$146***	***$146***	***$146***	***$146***
Total Revenues	**(B) x (C) = (D)***		**$10.1**	**$9.9**	**$9.6**	**$9.4**	**$9.1**	**$7.3**
Total Charging Cost [3]	(E)		($3.2)	($3.2)	($3.1)	($3.1)	($3.1)	($3.3)
Total O&M [4]	(F)*		(1.2)	(1.2)	(1.5)	(1.5)	(1.5)	(1.7)
Total Operating Costs	**(E) + (F) = (G)**		($4.4)	($4.4)	($4.6)	($4.6)	($4.6)	($4.9)
EBITDA	**(D) - (G) = (H)**		**$5.8**	**$5.5**	**$5.0**	**$4.7**	**$4.5**	**$2.3**
Debt Outstanding - Beginning of Period	(I)		$6.9	$6.7	$6.6	$6.4	$6.2	$0.7
Debt - Interest Expense	(J)		(0.6)	(0.5)	(0.5)	(0.5)	(0.5)	(0.1)
Debt - Principal Payment	(K)		(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.7)
Levelized Debt Service	(J) + (K) = (L)		(0.7)	(0.7)	(0.7)	(0.7)	(0.7)	(0.7)
EBITDA	**(H)**		$5.8	$5.5	$5.0	$4.7	$4.5	$2.3
Depreciation (7-yr MACRS)	(M)		(4.9)	(8.4)	(6.0)	(4.3)	(3.1)	0.0
Interest Expense	(J)		(0.6)	(0.5)	(0.5)	(0.5)	(0.5)	(0.1)
Taxable Income	**(H) + (M) + (J) = (N)**		**$0.3**	**($3.5)**	**($1.6)**	**($0.1)**	**$0.9**	**$2.3**
Tax Benefit (Liability)	**(N) x (Tax Rate) = (O)**		**($0.1)**	**$0.7**	**$0.3**	**$0.0**	**($0.2)**	**($0.5)**
After-Tax Net Equity Cash Flow	**(H) + (L) + (O) = (P)**	**($27.6)** [7]	**$5.0**	**$5.2**	**$4.5**	**$4.0**	**$3.6**	**$1.2**

IRR For Equity Investors	**12.0%**

Key Assumptions [5]	
Power Rating (MW)	100
Duration (Hours)	2
Usable Energy (MWh)	200
90% Depth of Discharge Cycles/Day	1
Operating Days/Year	350
Capital Structure:	
Debt	20.0%
Cost of Debt	8.0%
Equity	80.0%
Cost of Equity	12.0%
Taxes	
Combined Tax Rate	21.0%
Contract Term / Project Life (years)	20
MACRS Depreciation Schedule	7 Years
Total Initial Installed Cost ($/MWh) [6]	$172
O&M, Warranty & Augmentation Cost ($/MWh)	$20
Charging Cost ($/kWh)	$0.042
Charging Cost Escalator (%)	1.87%
Efficiency (%)	91%

■ Technology-dependent
■ Levelized

Source: Lazard and Roland Berger estimates.
Note: Wholesale (100 MW / 200 MWh)—Low LCOS case presented for illustrative purposes only. Assumptions specific to Wholesale (100 MW / 200 MWh) Low Case.
* Denotes unit conversion.
(1) Assumes half-year convention for discounting purposes.
(2) Total Generation reflects (Cycles) x (Available Capacity) x (Depth of Discharge) x (Duration). Note for the purpose of this analysis, Lazard accounts for Degradation in the Available Capacity calculation.
(3) Charging Cost reflects (Total Generation) / [(Efficiency) x (Charging Cost) x (1 + Charging Cost Escalator)].
(4) O&M costs include general O&M ($1.53/kWh, plus relevant Solar PV O&M, escalating annually at 2.5%), augmentation costs (3.0% of ESS equipment) and warranty costs (0.9% of equipment, starting in year 3).
(5) Reflects a "key" subset of all assumptions for methodology illustration purposes only. Does not reflect all assumptions.
(6) Initial Installed Cost includes Inverter cost of $38.05/kW, Module cost of $115.00/kWh, Balance of System cost of $32.46/kWh and a 3.6% engineering procurement and construction ("EPC") cost.
(7) Reflects the initial investment made by the project owner.

Levelized Cost of Storage—Key Assumptions

	Units	Wholesale (Standalone) (100 MW / 100 MWh)	Wholesale (Standalone) (100 MW / 200 MWh)	Wholesale (Standalone) (100 MW / 400 MWh)	Transmission & Distribution (10 MW / 60 MWh)	Utility-Scale (PV + Storage) (50 MW / 200 MWh)	Commercial & Industrial (Standalone) (1 MW / 2 MWh)	Commercial & Industrial (PV + Storage) (0.5 MW / 2 MWh)	Residential (PV + Storage) (0.006 MW / 0.025 MWh)
Power Rating	MW	100	100	100	10	50	1	0.5	0.006
Duration	Hours	1.0	2.0	4.0	6.0	4.0	2.0	4.0	4.2
Usable Energy	MWh	100	200	400	60	200	2	2	0.025
Discharge Cycles/Day	#	1	1	1	1	1	1	1	1
Operating Days/Year	#	350	350	350	25	350	250	350	350
Solar PV Capacity	MW	0.00	0.00	0.00	0.00	100.00	0.00	1.00	0.010
Annual Solar PV Generation	MWh	0	0	0	0	203,670	0	1,708	14
Project Life	Years	20	20	20	20	20	10	20	20
Memo: Annual Used Energy	*MWh*	*31,500*	*63,000*	*126,000*	*1,350*	*63,000*	*450*	*630*	*8*
Memo: Project Used Energy	*MWh*	*630,000*	*1,260,000*	*2,520,000*	*27,000*	*1,260,000*	*4,500*	*12,600*	*158*
Initial Capital Cost—DC	$/kWh	$172 – $250	$147 – $239	$147 – $231	$218 – $305	$169 – $460	$292 – $346	$303 – $628	$454 – $780
Initial Capital Cost—AC	$/kW	$20 – $83	$38 – $86	$25 – $66	$54 – $76	$49 – $102	$43 – $59	$49 – $170	$97 – $154
EPC Costs	$	$1 – $5	$1 – $9	$2 – $21	$1 – $3	$2 – $10	$0 – $0	$0 – $0	$0 – $0
Solar PV Capital Cost	$/kW	$0 – $0	$0 – $0	$0 – $0	$0 – $0	$775 – $775	$0 – $0	$2,125 – $2,125	$2,675 – $2,675
Total Initial Installed Cost	$	$20 – $38	$34 – $66	$63 – $119	$15 – $22	$118 – $190	$1 – $1	$3 – $4	$0 – $0
O&M	$/kWh	$1.7 - $3.8	$1.5 - $3.8	$1.5 - $2.5	$0.6 - $1.3	$1.1 - $18.0	$19.2 - $2.7	$0.4 - $19.4	$0.0 - $0.0
Extended Warranty Start	Year	3	3	3	3	3	3	3	3
Warranty Expense % of Capital Costs	%	0.90% - 0.90%	0.90% - 0.80%	0.90% - 1.24%	0.67% - 0.90%	1.00% - 1.73%	1.40% - 1.10%	0.10% - 1.45%	0.00% - 0.00%
Investment Tax Credit	%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Production Tax Credit	$/MWh	$0	$0	$0	$0	$0	$0	$0	$0
Charging Cost	$/MWh	$39	$42	$35	$30	$0	$107	$0	$0
Charging Cost Escalator	%	1.87%	1.87%	1.87%	1.87%	0.00%	2.15%	0.00%	0.00%
Efficiency of Storage Technology	%	91% – 84%	91% – 84%	91% – 84%	83% – 83%	85% – 77%	78% – 94%	85% – 78%	95% – 89%
Levelized Cost of Storage	$/MWh	$160 - $279	$146 - $257	$131 - $232	$1,613 - $3,034	$85 - $158	$442 - $643	$235 - $335	$416 - $621

Source: *Lazard and Roland Berger estimates.*

Note: Assumed capital structure of 80% equity (with a 12% cost of equity) and 20% debt (with an 8% cost of debt). Capital cost units are the total investment divided by the storage equipment's energy capacity (kWh rating) and inverter rating (kW rating). Lithium cases were modeled using 90% depth of discharge, Flow cases were modeled using 100% depth of discharge. Wholesale and Transmission & Distribution charging costs use the EIA's "2020 Wholesale Price $/MWh– Wtd Avg Low" price estimate of $30.08/MWh. Escalation is derived from the EIA's "AEO 2021 Energy Source–Electric Price Forecast (20-year CAGR)" and ranges from 1.87% – 2.15% by use case. Storage systems paired with Solar PV do not charge from the grid.

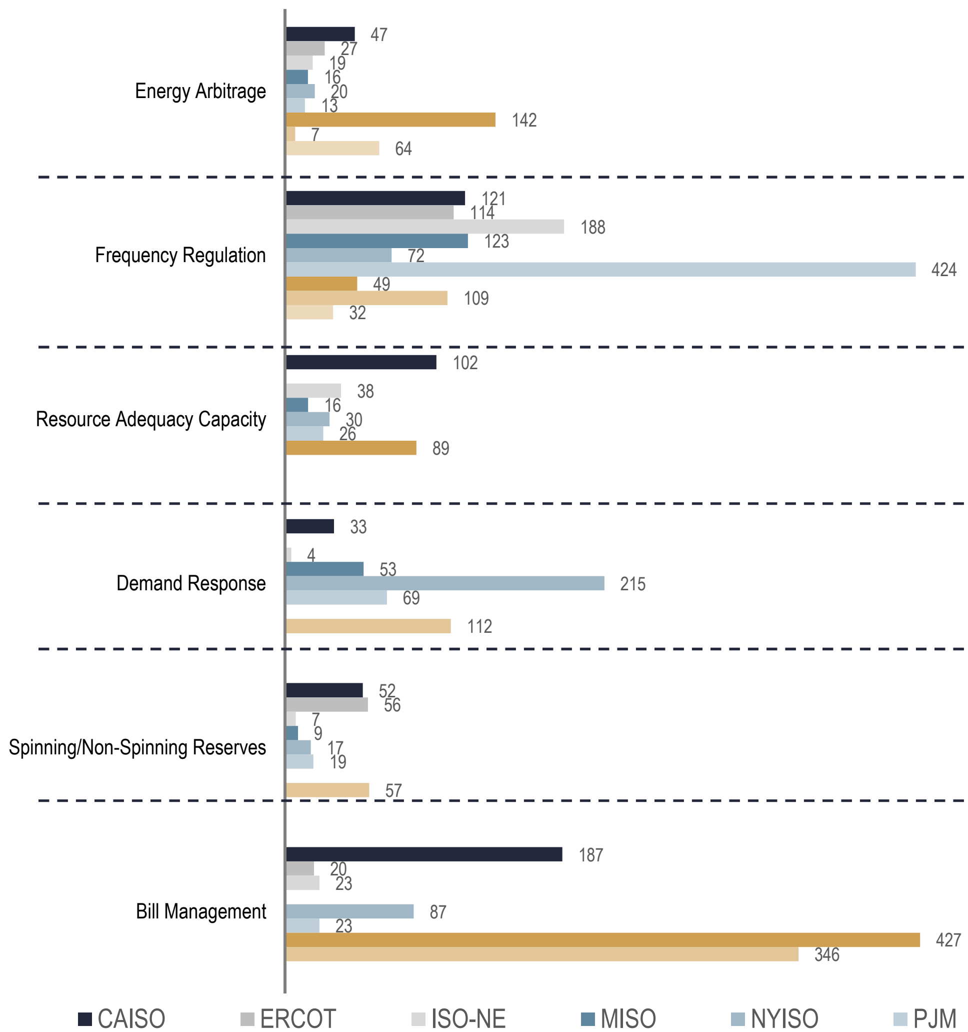
B Value Snapshot Case Studies

Overview of Energy Storage Revenue Streams

($/kW-year, unless otherwise noted)

To show indicative revenue potential by use case and market, Lazard's LCOS analyzes front-of-the-meter ("FTM") and behind-the-meter ("BTM") revenue streams from currently deployed energy storage systems(1)

Revenue Streams(2)(3)



Observations

- Revenues from energy markets have declined year-over-year across domestic ISOs, while international markets are generally flat
- The lack of regional interconnection of Australia's transmission system remains apparent, generating arbitrage opportunities in Victoria and Queensland, i.e., the most evident opportunity observed in this study

- While attractive on an opportunistic basis, frequency regulation markets lack depth and risk being saturated as additional resources enter the market
- PJM provides the most potential revenue, though year-over-year pricing is highly volatile and unpredictable

- Resource adequacy ("RA") continues to be opaque in California/CAISO
- Elsewhere, storage projects can qualify for capacity market revenues, though duration requirements remain a hurdle for certain markets (e.g., NY-ISO and PJM)

- NY-ISO has highly attractive potential revenue, though in practice the most attractive location, New York City, has limited project opportunities
- Limited opportunity for demand response revenue streams beyond Ontario IESO, PJM, NY-ISO and Australia

- Spin/Non-Spin reserve revenues have declined across domestic ISOs
- Hybrid resources in California (e.g., solar plus gas-fired generators) utilize these markets in addition to RA values to enhance project economics
- CAISO, ERCOT and Ontario IESO offer the highest potential revenues

- Avoidance of Australia's NSP56 Demand Capacity & Critical Peak tariffs offers the highest potential bill savings for C&I customers
- Ontario IESO's Global Adjustment Charge continues to be a highly attractive opportunity despite portions of the global adjustment cost being shifted from rate payers to taxpayers through the Non-Hydro Renewables Funding program
- Meaningful bill savings opportunities can also be found in CAISO

Source: *Enovation Analytics, Lazard and Roland Berger estimates.*
Note: All figures presented in USD using the following exchange rates: USD 0.69/AUD, USD 0.75/CAD and USD 1.14/EUR.
(1) Assumes standalone battery is deployed without co-located solar PV.
(2) Represents the universe of potential revenue streams available to the various use cases.
(3) Wholesale revenues based on wholesale prices from the 12 months prior to the onset of the COVID-19 pandemic (i.e., February 2019 – February 2020) in order to normalize the underlying data. BTM revenues are based on the most recent tariffs, programs and incentives available as of 1H 2021.

1 Value Snapshot Case Studies—U.S.

1 Wholesale, CAISO (Los Angeles, California)

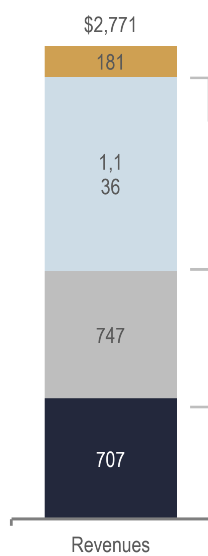
100 MW / 400 MWh Standalone Battery

- **Project IRR: 23.7%(1)**

Use Case Commentary

- **Additional use case context:**
  - The project utilizes an AC-coupled battery at a node in the Los Angeles basin
  - Charging costs average $34.58/MWh
  - To generate energy arbitrage revenue, the battery typically charges during the day and discharges during peak load periods in the evening
  - The project is developed to provide capacity under local RA parameters
  - To maximize additional revenues, the battery optimally allocates itself to Frequency Regulation and Spin/Non-Spin based on current market pricing
  - To avoid distortions from COVID-19 related impacts, wholesale prices from the 12 months prior to the onset of the pandemic (February 2019 – February 2020) are used as the baseline for modeling energy prices over the forecast period
- **Market observations:**
  - Resource adequacy contract pricing has increased year-on-year, with most market participants reporting pricing in the range of $5 – $10/kW-month
  - Given that the California energy storage development pipeline is greater than the size of the CAISO regulation market, prices for frequency regulation are not expected to continue to increase, and may decline beyond 2025
  - Idiosyncratic factors (e.g., Public Safety Power Shutoff events ("PSPS"), wildfires and heat stress) drive volatility in market conditions and support the need for resilience-based procurement models
    - Increasing penetration of renewables will continue to drive curtailment and periods of negative energy pricing

Value Snapshot Revenues(1) ($/kW)



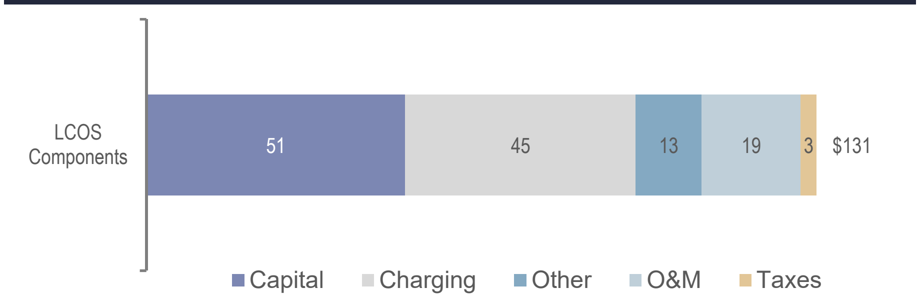
Spin/Non-Spin Reserves
- Weighted average dispatch: $8.35/MWh
- Deployed 20% of the time(2)
- 63% correlated to energy price movements

Frequency Regulation
- Weighted average dispatch price: $10.64/MWh (up), $11.86/MWh (down)
- 61% (up) and 5% (down) correlated to energy prices
- Deployed 82% of the time(2)

Energy Arbitrage
- Average dispatch price: $47.48/MWh (range of $0/MWh to over $1,045/MWh)
- Average charging is $41.55/MWh
- Deployed 84% of the time(2)

Resource Adequacy
- $7.5/kW-month
- Operators must conform to System, Local, or Flexible RA requirements

Levelized Cost of Storage(1) ($/MWh)



Source: Industry interviews, Enovation Analytics, Lazard and Roland Berger.
Note: Analysis assumes the project will reach commercial operation in 2022.
(1) NPV of lifetime project revenues is presented. Cost structure representative of the "Average Case" is used in the IRR analysis and shown in the LCOS summary.
(2) Average amount of time deployed in given revenue stream during 2022. Sum of time deployed may exceed 100% because battery can participate in multiple revenue streams simultaneously.

2 T&D Deferral, REC (Spotsylvania County, Virginia)

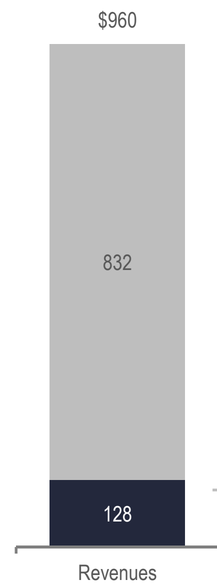
2 MW / 8 MWh Standalone Battery

- **Project IRR: 8.5%[1]**

Use Case Commentary

- **Additional use case context:**
  - The T&D deferral Value Snapshot is based on estimates of actual cost and revenue data for a project developed by REC that is expected to reach commercial operations in 2022
  - The storage asset allows REC to defer investments to upgrade components of the distribution grid that are nearing thermal limits
  - The battery cycles an average of seven times per month, and is dispatched during "demand control periods" to avoid distribution system overload, as well as to decrease wholesale power procurement costs by reducing peak load
  - Charging costs are based on REC's contracted wholesale energy procurement rate; however, battery discharge offsets these costs causing the effective charging costs to be the round-trip efficiency losses from cycling the battery
- **Market observations:**
  - Economics continue to limit deployment of pure T&D deferral use cases, even in regions with "non-wires alternative" planning regimes
  - Current FERC regulations generally prevent utility ownership of generation resources in deregulated jurisdictions, making these resources ineligible to participate in energy and capacity markets. As a result, few utilities are currently investing in storage for T&D deferral cases
- **Other use case assumptions:**
  - REC is using Rural Utility Service ("RUS") financing for the project, which carries an annual interest rate of ~2.6%
  - Battery installation and substation work was performed by REC personnel; project economics assume no additional labor costs are incurred

Value Snapshot Revenues[1][2] ($/kW)



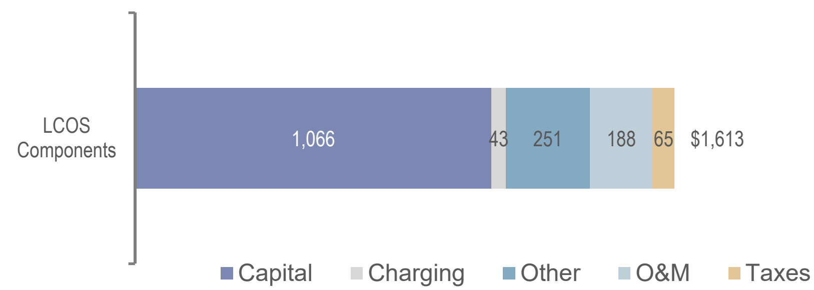
Demand Response—Wholesale

- REC is assessed capacity charges as a load-serving entity in the PJM market, which are a function of coincident load during monthly and annual system peaks. The battery is dispatched to reduce coincident peak load. Annual savings are estimated by REC to be ~$211,000

Distribution Deferral

- The storage asset allows REC to defer investments in two separate substation upgrades for three years

Levelized Cost of Storage[1][2] ($/MWh)



Source: REC, EIA, Industry interviews, Lazard and Roland Berger.

Note: LCOS data reflect project parameters corresponding to the illustrative T&D deferral use case as outlined on the page titled "Energy Storage Use Cases—Illustrative Operational Parameters", (i.e., a standalone 10 MW / 60 MWh battery). Operational parameters used in the Value Snapshots analysis correspond to parameters unique to the project analyzed.

(1) NPV of lifetime project revenues is presented. Cost structure representative of the "Average Case" is used in the IRR analysis and shown in the LCOS summary.

(2) Given the operational parameters for the Transmission and Distribution use case (i.e., 25 cycles per year), levelized metrics are not comparable between this and other use cases presented in Lazard's Levelized Cost of Storage report.

3 Wholesale PV+Storage, ERCOT (Corpus Christi, Texas)

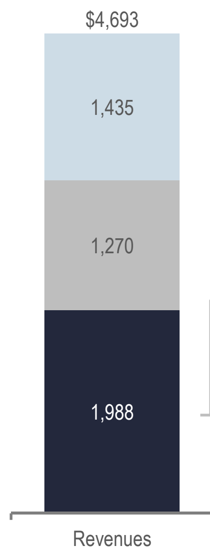
50 MW / 200 MWh Battery, paired with 100 MW of Solar PV

- **Project IRR: 29.1%[(1)]**

Use Case Commentary

- **Additional use case context:**
  - The project utilizes an AC-coupled battery at a node in South Texas. The AC-coupled system was chosen to demonstrate the advantage of higher PV system efficiency and avoid inverter capacity limitations
  - The battery charges exclusively from the coupled solar PV system for the first five years of operation in order to maintain eligibility for the Federal Solar Investment Tax Credit ("ITC")
- **Market observations:**
  - To avoid distortions from COVID-19 related impacts, wholesale prices from the 12 months prior to the onset of the pandemic (February 2019 – February 2020) are used as the baseline for modeling energy prices over the forecast period
  - ERCOT wholesale energy prices were higher than historical averages in 2019, averaging $38/MWh for the calendar year
    - This is primarily due to the volatility caused by extreme heat waves. In August 2019, day-ahead pricing averaged $127/MWh. Ancillary services prices were also elevated during these events
    - For comparison, annual average energy prices were $34/MWh and $25/MWh in 2018 and 2020, respectively
  - Recent trends in build sizes:
    - Larger energy storage systems are typically coupled with solar PV systems (>2 hours duration, >50 MWh) vs. on a standalone basis
    - Smaller, 1 – 2 hour batteries are being deployed on a standalone basis, in part to address curtailment and negative pricing. Projects <10 MW are exempt from most interconnection requirements

Value Snapshot Revenues[(1)] ($/kW)

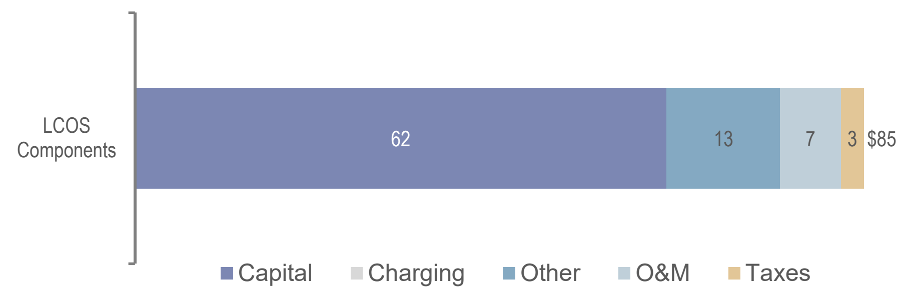


Frequency Regulation ("FR")
- Weighted average dispatch price: $58.50 (up), $18.24 (down)/MWh
- Deployed 18% of the time[(2)]

Energy Arbitrage
- Median dispatch price: $27.22/MWh (range of $5 to over $2,000/MWh)
- Deployed 49% of the time[(2)]

Spin/Non-Spin Reserves
- Weighted average dispatch price: $36.70/MWh
- Deployed 69% of the time[(2)]
- 91% correlated to energy price movements

Levelized Cost of Storage[(1)] ($/MWh)



Source: Industry interviews, Enovation Analytics, Lazard and Roland Berger.
Note: Analysis assumes the project will reach commercial operation in 2022.
(1) NPV of lifetime project revenues is presented. Cost structure representative of the "Average Case" is used in the IRR analysis and shown in the LCOS summary.
(2) Average amount of time deployed in given revenue stream during 2021. Sum of time deployed may exceed 100% because battery can participate in multiple revenue streams simultaneously.

4 C&I Standalone, PG&E (San Francisco, California)

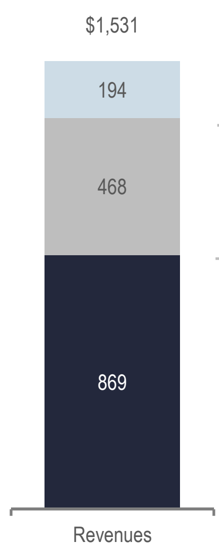
1 MW / 2 MWh Battery

- **Project IRR: 26.4%[(1)]**

Use Case Commentary

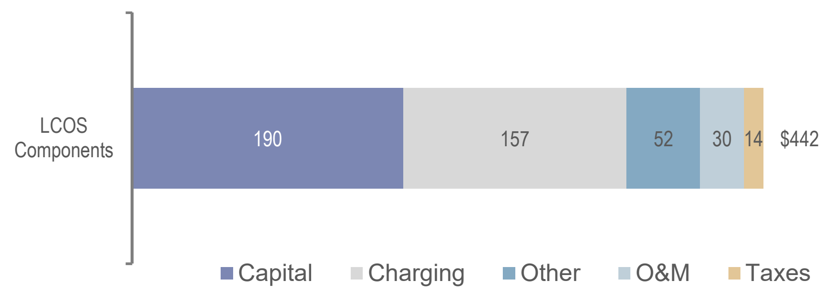
- **Additional use case context:**
  - The project utilizes a standalone AC-coupled battery and the load shape of a large office building in San Francisco
  - Charging costs are an average of $102.33/MWh, reflecting the local TOU rate
  - The project is developed to reduce energy load during periods of peak pricing, in turn reducing the end-customer's electricity costs
  - Additional revenues are captured through participation in Demand Response and local Self-Generation Incentive Program ("SGIP") programs
- **Market observations:**
  - PG&E has migrated C&I customers from the legacy E-20 tariff to the B-20 tariff. Key differences include lower demand charges and greater disparity between peak and off-peak energy prices
  - SGIP funding: as of July 2021, ~80% of funds allocated to large-scale projects in PG&E Step 4 (i.e., ~$40 million) remain available
  - Developers continue to move away from bill management use cases and towards backup power applications given the increased focus on grid reliability and resiliency
    - Developers are also preparing for potentially challenged economics for C&I batteries when incentive programs expire
  - C&I projects have substantially higher relative permitting and installation costs vs. utility-scale projects
    - Many OEMs are developing "turnkey crate" solutions whereby a fully integrated storage system is delivered to the site, reducing overall EPC costs

Value Snapshot Revenues[(1)] ($/kW)



Demand Response—Utility	PG&E's Capacity Bidding Program provides monthly capacity payments averaging $11.10/kW-month for May through October
Local Incentive Payments	PG&E's SGIP incentives for commercial building use cases is $300,000/MWh
Bill Management	The project participates in PG&E's B-20 TOU Tariff (2021 baseline)

Levelized Cost of Storage[(1)] ($/MWh)



Source: Industry interviews, PG&E, Enovation Analytics, Lazard and Roland Berger.
Note: Analysis assumes the project will reach commercial operation in 2022.
(1) NPV of lifetime project revenues is presented. Cost structure representative of the "Average Case" is used in the IRR analysis and shown in the LCOS summary.

5 C&I PV+Storage, PG&E (San Francisco, California)

0.5 MW / 2 MWh Battery, paired with 1 MW of Solar PV

- **Project IRR: 23.4%[1]**

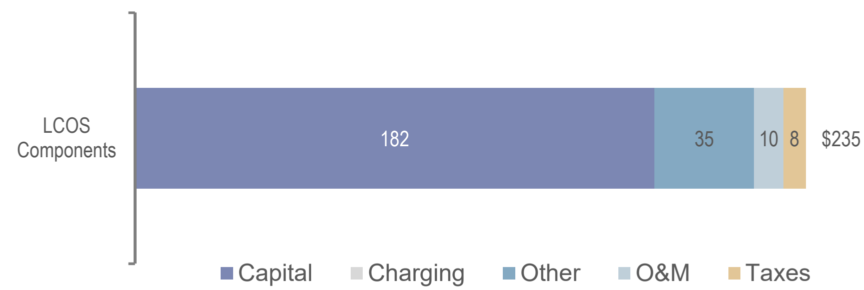
Use Case Commentary

- **Additional use case context:**
  - The project utilizes a DC-coupled battery and the load shape of a large office building in San Francisco. DC coupling was chosen to demonstrate the advantage of relatively higher overall system efficiency, capture of solar clipping and simplicity of installation
  - The battery charges exclusively from the coupled solar PV system for the first five years of operation in order to maintain eligibility for the ITC
  - The project is developed to reduce energy load during periods of peak pricing, in turn reducing the end-customer's electricity costs
  - Additional revenues are captured through participation in Demand Response and local Self-Generation Incentive Program ("SGIP") programs
- **Market observations:**
  - PG&E has migrated C&I customers from the legacy E-20 tariff to the B-20 tariff. Key differences are a lower demand charge, but greater disparity between peak and off-peak energy rates
  - SGIP funding: as of July 2021, ~80% of funds allocated to large-scale projects in PG&E Step 4 (i.e., ~$40 million) remain available
  - Developers continue to move away from bill management use cases and towards backup power applications given the increased focus on grid reliability and resiliency
    - Developers are also preparing for potentially challenged economics for C&I batteries when incentive programs expire
  - The value of selling excess solar generation back to the grid (i.e., net metering) continues to decline as abundant solar generation during hours of peak solar production depress energy prices
  - California's aggressive Zero Net Energy ("ZNE") Plan will require all new commercial buildings to be ZNE by 2030 and 50% of existing commercial buildings to be retrofitted to comply with the ZNE Plan by 2030, supporting aggressive growth in this use case over the next decade

Value Snapshot Revenues[1] ($/kW)

Demand Response—Utility	PG&E's Capacity Bidding Program provides monthly capacity payments averaging $11.10/kW-month for May through October
Local Incentive Payments	PG&E's SGIP incentives for this project type (commercial building paired with solar, receiving the ITC) valued at $220,000/MWh
Bill Management	The system participates in PG&E's B-20 TOU Tariff (2020 baseline)

Levelized Cost of Storage[1] ($/MWh)



Source: *Industry interviews, PG&E, Enovation Analytics, Lazard and Roland Berger.*
Note: Analysis assumes the project will reach commercial operation in 2022.
(1) NPV of lifetime project revenues is presented. Cost structure representative of the "Average Case" is used in the IRR analysis and shown in the LCOS summary.

6 Residential PV+Storage, HECO (Honolulu, Hawaii)

0.006 MW / 0.025 MWh battery, paired with 0.010 MW of Solar PV

- **Project IRR: 9.4%(1)**

Use Case Commentary

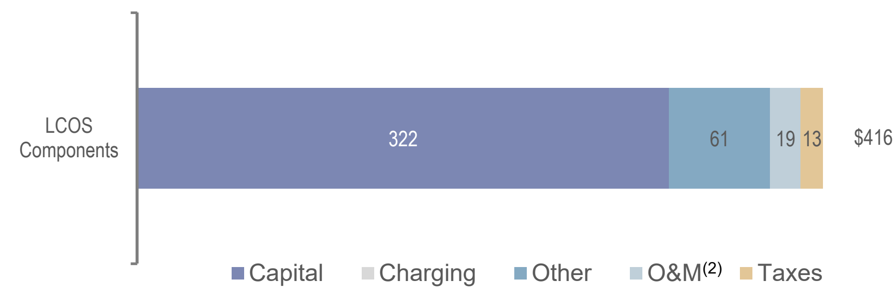
- **Additional use case context:**
  - The project utilizes an AC-coupled battery and the load shape of a large single-family residence in Hawaii
  - The battery charges exclusively from the coupled solar PV system for the first five years of operation in order to maintain eligibility for the ITC
  - The project is developed to reduce energy load during periods of peak pricing, in turn reducing the end-customer's electricity costs
  - Battery storage trends in Hawaii:
    - Historically, due to the island's energy constraints, much of Hawaii's electricity was produced using oil-fired generation resources. Transportation costs and underlying oil price volatility led to expensive and volatile electricity prices
    - The initial Net Energy Metering ("NEM") programs were advantageous to retail customers, with HECO providing bill credits at the avoided retail rate for electricity produced in excess of the customer's energy load
    - In 2015, NEM rules were changed so new tariffs reflected customer credits based on avoided variable generation costs for HECO, rather than the retail rate, significantly reducing attractiveness of standalone PV
- **Market observations:**
  - Hawaii has high electricity tariffs, favorable insolation, growing renewable energy penetration and an active Public Utility Commission
  - Grid instability, weather and volcanic risks cause reliability and resilience issues for HECO, further incentivizing residential energy storage
  - The state has among the most aggressive renewable energy targets, coupled with a supportive policy framework

Value Snapshot Revenues(1) ($/kW)

Bill Management

- This hybrid system qualifies for the ITC
- The battery is used solely to manage the customer's bill by using solar PV generation to offset load during periods of peak pricing
- The system participates in HECO's Schedule-R Tariff (2021 baseline)

Levelized Cost of Storage(1) ($/MWh)



Source: Industry interviews, HECO, Enovation Analytics, Lazard and Roland Berger.
Note: Analysis assumes the project will reach commercial operation in 2022.
(1) NPV of lifetime project revenues is presented. Cost structure representative of the "Average Case" is used in the IRR analysis and shown in the LCOS summary.
(2) Lifetime O&M for this use case is included in the initial capital investment.

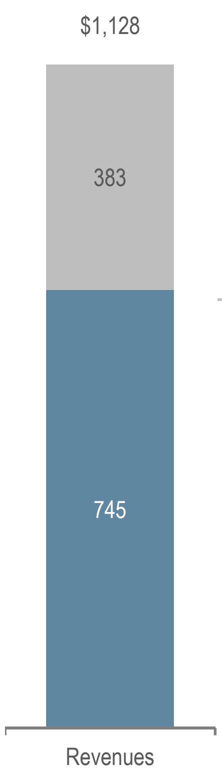
2 Value Snapshot Case Studies—International

International Value Snapshots

1 Wholesale, Germany (Bavaria)(1) ($/kW)

100 MW / 400 MWh standalone battery

- Project IRR: 6.5%(1)



Frequency Regulation

- Average estimated realized unit prices for Frequency Response sub-classes, base period:
  - FCR Capacity payments: $40.36/MW (up & down)
  - mFRR Capacity payments: $25.84/MW up
- Assumes 0.2% probability to be called on for energy participation
- Participation based on pricing for four-hour blocks
- No participation in aFRR classes

Energy Arbitrage

- Average realized energy arbitrage price, base period: ~$50/MWh
  - Range of $0/MWh – $103.62/MWh
- Median charging price, 2022: ~$27/MWh
- Energy prices based on February 2019 – February 2020 day-ahead prices (operating within the Tennet TSO)
- Annual escalation of 4.3%

3 Wholesale PV+Storage, Australia (Queensland)(1) ($/kW)

50 MW / 200 MWh battery paired with 100 MW of Solar PV

- Project IRR: 12.8%(1)

Frequency Regulation

- Average estimated unit price, 2022:
  - $24.46/MW (up & down)
- Participation in Queensland ancillary services (i.e., Lower & Raise, 6 seconds, 5 minute, Regulation, Restart, Reactive)

Resource Adequacy

- Average estimated unit price, 2022:
  - $154,200/MW-year
- Benchmark Reserve Capacity Price from Australia Energy Market Operator
- Annual escalation of -0.9%

Energy Arbitrage

- Median energy arbitrage price, 2022: ~57/MWh
  - Range of $0/MWh – $4,790/MWh
- Energy prices based on 2019 and 2020 Queensland region
- Assumes the battery is discharged during the top four hours of each day
- Annual escalation of 4.7%

Source: Industry interviews, IESO, AER, Energy Storage World Forum, German Association of Energy and Water Industries, Lazard and Roland Berger.

Note: International and domestic use cases utilize the same capital cost assumptions. All figures presented in USD using the following exchange rates: USD 0.69/AUD, USD 0.75/CAD and USD 1.14/EUR. Base period is assumed to be from February 1, 2019 through January 31, 2020 to avoid distortions from the impact of the COVID-19 pandemic on wholesale power markets.

(1) NPV of lifetime project revenues is presented. Cost structure representative of the "Average Case" is used in the IRR analysis.

International Value Snapshots (cont'd)

4 C&I Standalone, Canada (Ontario) ($/kW)

1 MW / 2 MWh standalone battery

- Project IRR: 27.4%(1)

Bill Management

- Participates exclusively in Ontario IESO's Global Adjustment savings
  - Requires exact timing and participation in 5 – 10 peak load days per year
  - Savings are generated by avoiding peak global adjustment charges
  - Accurately predicting peak hours requires specialized analytics services, priced at $25,000 per year
- Value Snapshot methodology assumes participation in five peak load days per year
- Ontario/IESO "Class A" GAC
- The Ontario government has reduced total grid access charges by ~20% by shifting certain costs into the tax base and is planning to reduce total system costs moving forward

5 C&I PV+Storage, Australia (Victoria) ($/kW)

0.5 MW / 2 MWh battery paired with 1 MW of Solar PV

- Project IRR: 26.3%(1)

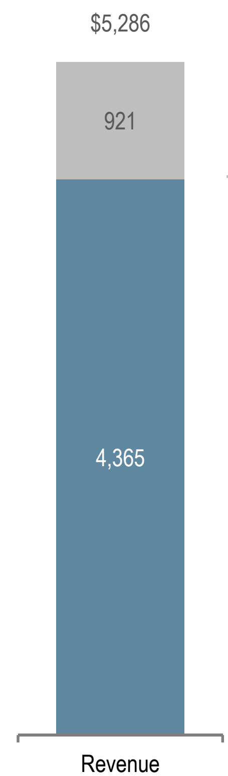
Bill Management

- Participation in AusNet's NSP56 Tariff structure
- Reduction of demand and energy charges are achieved through load shifting

6 Residential PV+Storage, Germany (Bavaria) ($/kW)

0.006 MW / 0.025 MWh battery paired with 0.1 MW of Solar PV

- Project IRR: 4.5%(1)



Local Incentive Payments

- Participation in Germany's home PV+storage incentive program offered by the German Development Bank
- Additional state-level incentive from Bavarian government, rolled out in 2020

Bill Management

- Assumes average residential retail electricity price of ~$31/MWh
- Reduction of energy charges through load shifting
- Residential rate is based on Bundesverband der Energie- und Wasserwirtschaft ("BDEW") pricing
- Annual escalation of 2.74%

Source: Industry interviews, IESO, AER, Energy Storage World Forum, German Association of Energy and Water Industries, Lazard and Roland Berger.

Note: International and domestic use cases utilize the same capital cost assumptions. All figures presented in USD using the following exchange rates: USD 0.69/AUD, USD 0.75/CAD and USD 1.14/EUR.

(1) NPV of lifetime project revenues is presented. Cost structure representative of the "Average Case" is used in the IRR analysis.