LAZARD'S LEVELIZED COST OF STORAGE ANALYSIS—VERSION 6.0

LAZARD

Table of Contents

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 v6.0
- **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
  - Supplementary materials for the Value Snapshot analysis, including additional informational regarding the revenue streams available to each use case

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

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

Technology	• Lithium-ion chemistries continue to be the dominant storage technology for short-duration applications (i.e., 1 – 4 hours), representing ~90% of the market – Competing technologies are less attractive for most applications given Lithium-ion's advantages in commercial acceptance, price, energy density and availability – Momentum in the energy storage market favors Lithium Iron Phosphate ("LFP") manufacturers, whose storage modules are less expensive and considered a potentially safer technology given higher temperature thresholds for thermal runaway • LFP's lower volumetric energy density is not viewed as overly detrimental for most stationary storage use cases • Segments of the vehicle market are also adopting LFP, creating the potential for continued scale benefits from EV adoption • Interest in long-duration storage solutions is growing as more projects reach pilot stages – Ideal applications currently include resilience, resource adequacy and capacity services, albeit concerns pertaining to round-trip efficiency and O&M persist – OEMs are focused on areas with potentially significant curtailment of renewable energy, (e.g., the U.S., Europe and South America), as well as resilience-related needs in California (e.g., SDG&E's Cameron Corners project) – Corporate customers and utility companies are also evaluating these technologies to satisfy long-term carbon reduction goals – Developers prefer to benchmark technology and project costs against natural gas peakers vs. other short-duration storage technologies, (e.g., Lithium-ion)
Use Cases	• The economic proposition of C&I behind-the-meter ("BTM") projects remains challenged without subsidies – Time-of-Use ("TOU") arbitrage is typically insufficient on its own to produce favorable economics for C&I BTM uses, and demand charge and demand response ("DR") revenues are sufficient only in a subset of markets (e.g., California and New York) – In select cases, the value proposition for C&I BTM storage appears to be shifting towards power reliability and resilience applications, with TOU arbitrage as a secondary benefit • Demand for PV+Storage use cases is primarily driven by utility procurements and the forthcoming step-down of the ITC – PV+Storage projects are becoming increasingly price competitive as utilities look for ways to supplement retiring conventional generation resources while avoiding investments in new peaking power plants – Demand for PV+Storage plants is also being enhanced by the desire to "lock in" favorable economics prior to the step-down of the ITC, as well as increased Independent System Operator ("ISO") sensitivity to intermittency as renewables penetration grows – The parameters associated with the ITC are leading developers to favor oversizing the initial system capacity vs. augmenting it over time as the storage modules degrade

II Lazard's Levelized Cost of Storage Analysis v6.0

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
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 • Flow Battery—Copper Zinc
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 • Flow Battery—Copper Zinc
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 • Flow Battery—Copper Zinc
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 revenues streams and subsidies	• Lithium Iron Phosphate • Lithium Nickel Manganese Cobalt Oxide • Flow Battery—Vanadium • Flow Battery—Zinc Bromine • Flow Battery—Copper Zinc
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]

- **There may be alternative or combined/"stacked" use cases available to energy storage systems**

[dashed box] = "Usable Energy"[2]

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	--	2.59%	1	100	1	350	31,500	630,000
		20	100	--	2.59%	2	200	1	350	63,000	1,260,000
		20	100	--	2.59%	4	400	1	350	126,000	2,520,000
	2 Transmission and Distribution[7]	20	10	--	1.46%	6	60	1	25	1,350	27,000
	3 Wholesale (PV+Storage)[7]	20	50	100	1.46%	4	200	1	350	63,000	1,260,000
Behind-the-Meter	4 Commercial & Industrial (Standalone)	10	1	--	2.02%	2	2	1	250	450	4,500
	5 Commercial & Industrial (PV+Storage)[7]	20	0.50	1	2.59%	4	2	1	350	630	12,600
	6 Residential (PV+Storage)	20	0.006	0.010	2.45%	4	0.025	1	350	8	158

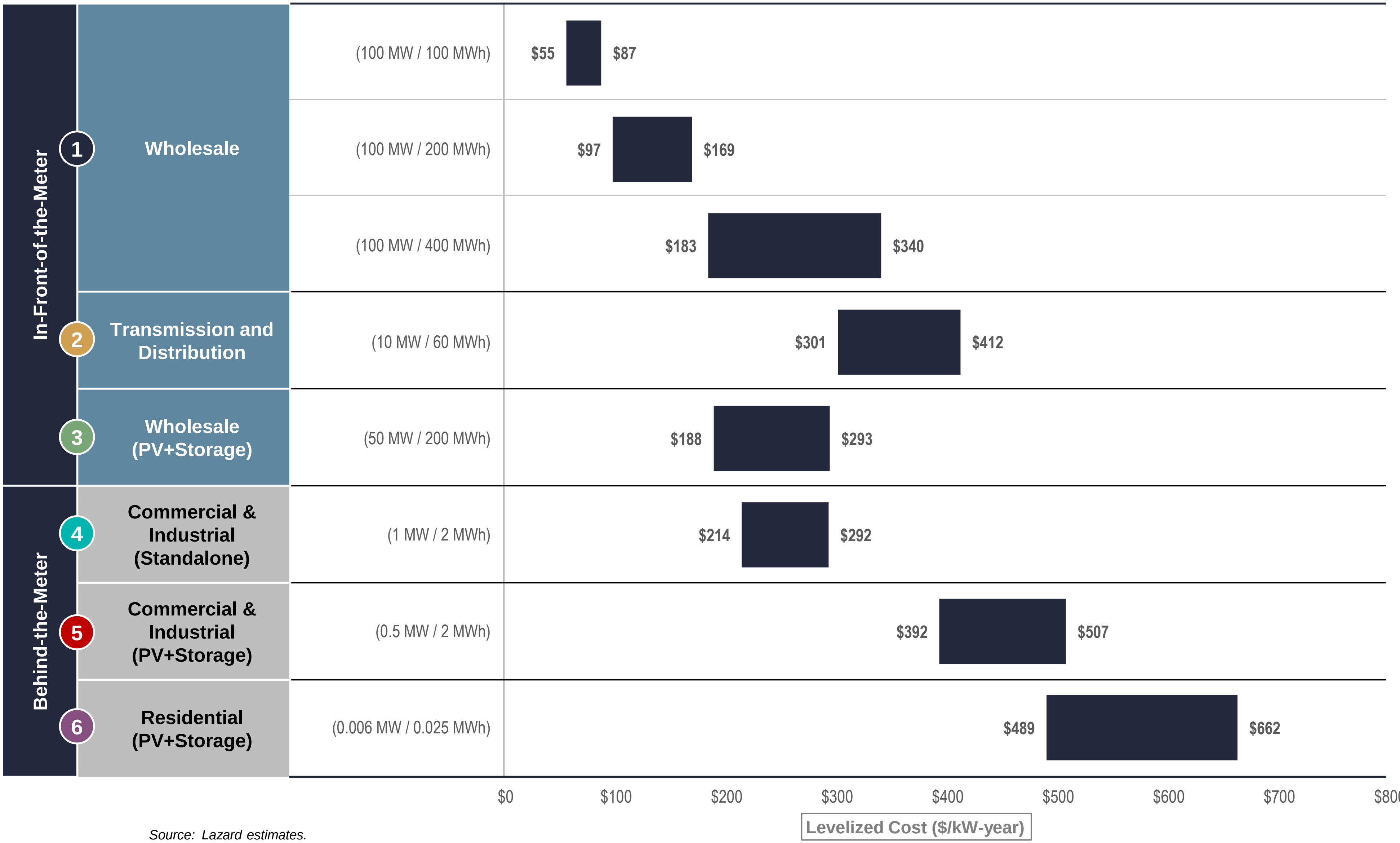
Source: Lazard and Roland Berger.

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 ability 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

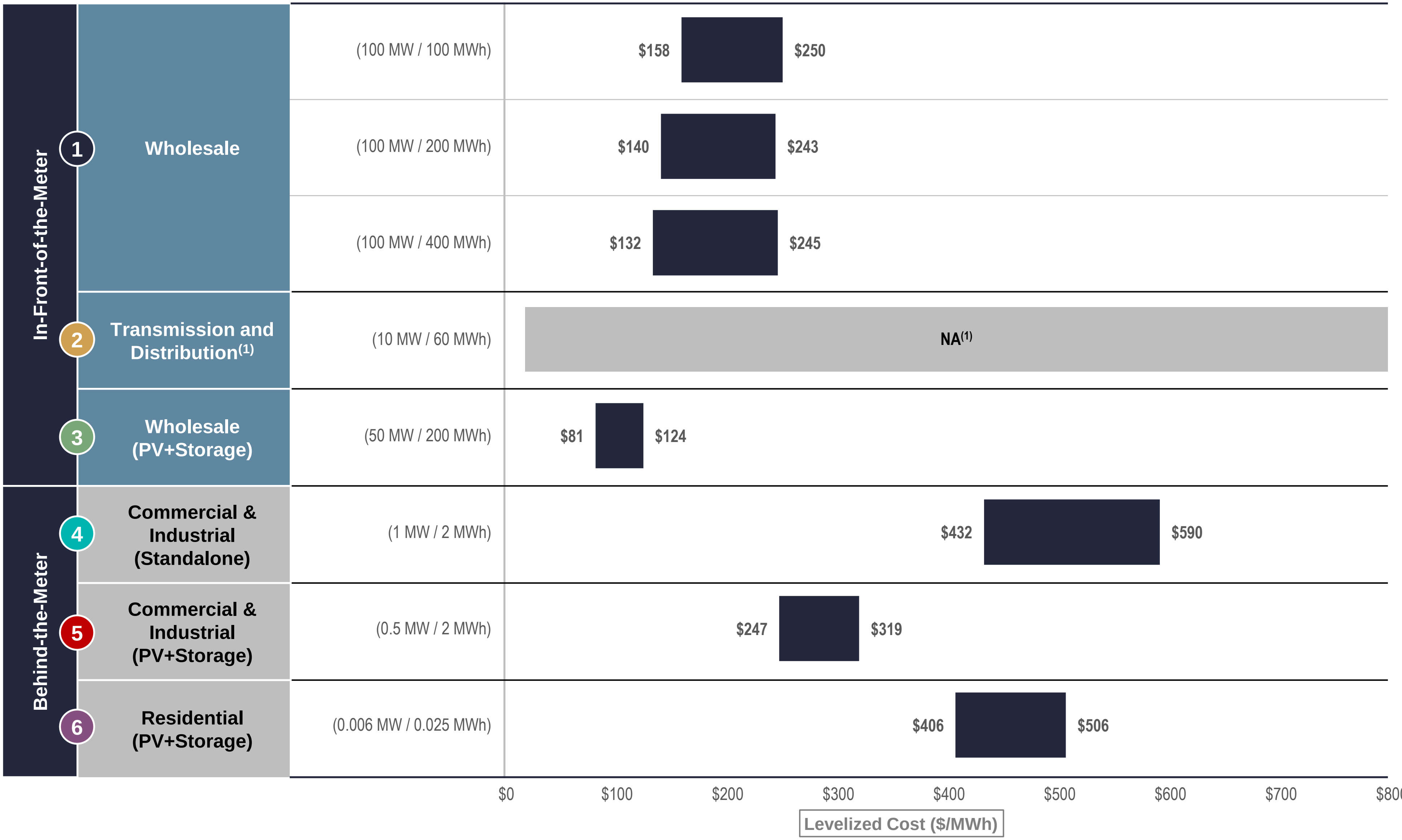


Source: *Lazard estimates.*

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 $2,025/MWh – $2,771/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				✓	✓	✓
	Energy Arbitrage	• Storage of inexpensive electricity to sell later at higher prices (only evaluated in the context of a wholesale market)	✓	✓	✓			
	Frequency Regulation	• Provides immediate (four-second) power to maintain generation-load balance and prevent frequency fluctuations	✓	✓	✓	✓	✓	
	Resource Adequacy	• Provides capacity to meet generation requirements at peak loading	✓	✓	✓	✓	✓	
	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		✓				
	Transmission Deferral	• Provides extra capacity to meet projected load growth for the purpose of delaying, reducing or avoiding transmission system investment		✓				
	Demand Response—Utility	• Manages high wholesale price or emergency conditions on the grid by calling on users to reduce or shift electricity demand				✓	✓	✓
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				✓	✓	✓
	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 represent the use cases 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 (vs. a cost perspective as in the LCOS)

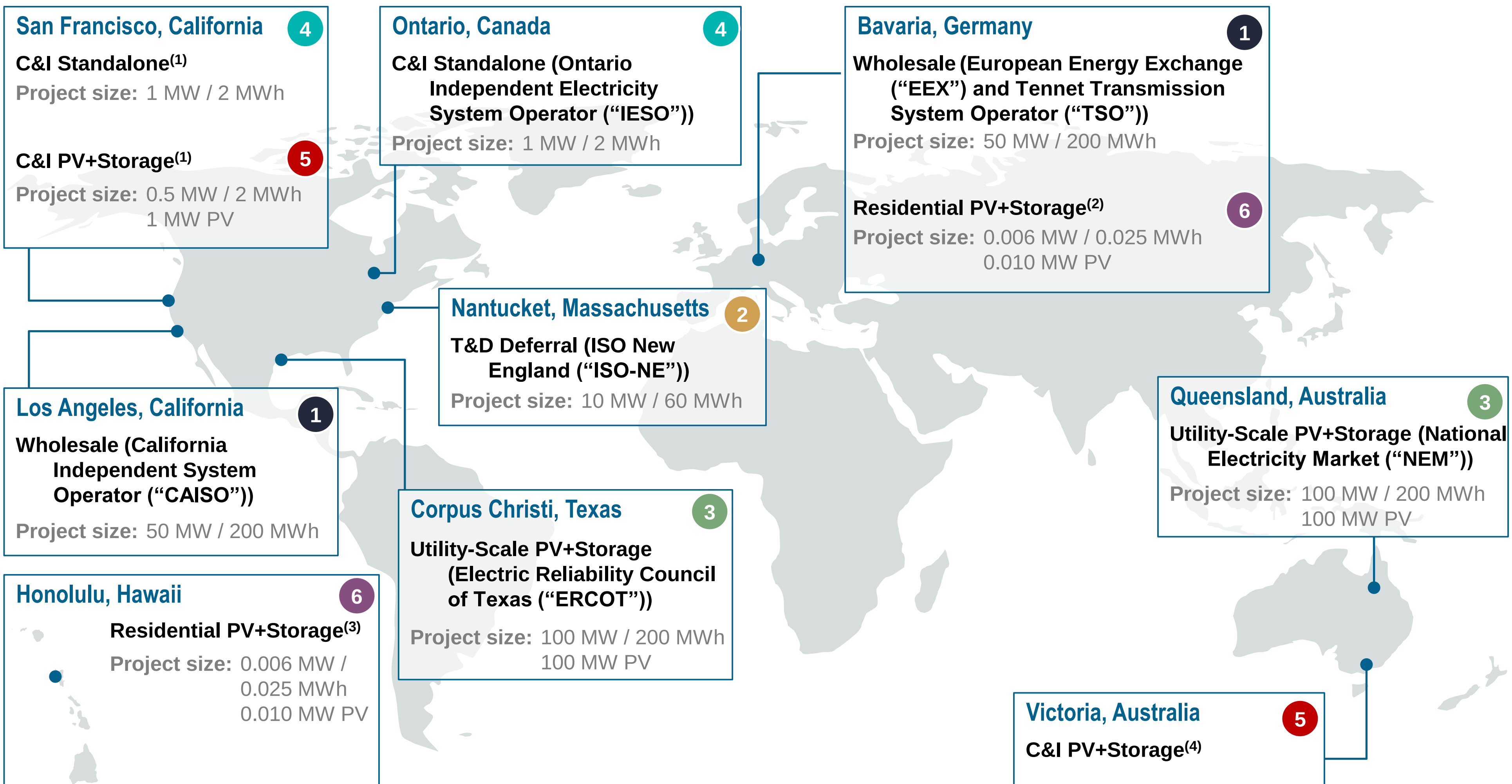
- **The geographic locations, assumed installed and operating costs and associated revenue streams reflect current energy storage market activity**

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	ISO-NE (Massachusetts)	--[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: 50 MW / 200 MWh

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

Nantucket, Massachusetts

2 **T&D Deferral (ISO New England ("ISO-NE"))**
Project size: 10 MW / 60 MWh

Los Angeles, California

1 **Wholesale (California Independent System Operator ("CAISO"))**
Project size: 50 MW / 200 MWh

Queensland, Australia

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

Corpus Christi, Texas

3 **Utility-Scale PV+Storage (Electric Reliability Council of Texas ("ERCOT"))**
Project size: 100 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

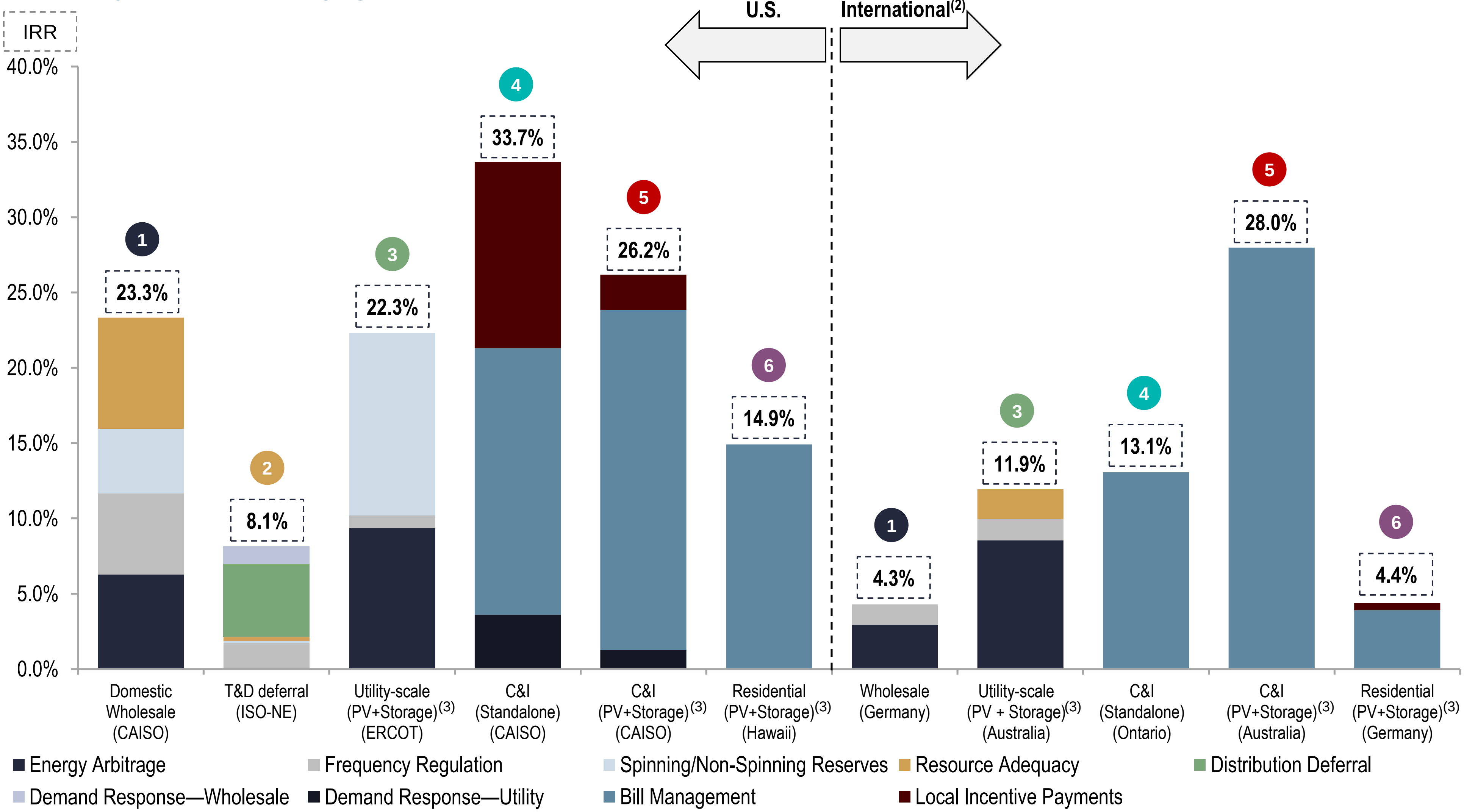
Victoria, Australia

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: U.S.$0.699/AUD, U.S.$0.741/CAD and U.S.$1.136/EUR.

(1) Cost structure representative of the "Low 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) 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	• No degradation • Cycling throughout the day • Modular options available • Limited 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	• Relatively expensive membrane materials • Relatively more difficult to scale production capacity • Lower energy density • Slightly higher O&M costs	• 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	• Substantial physical footprint vs. competing technologies • Difficult to modularize • Cycling limited to once per day • Lower efficiency (e.g., CAES systems)

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

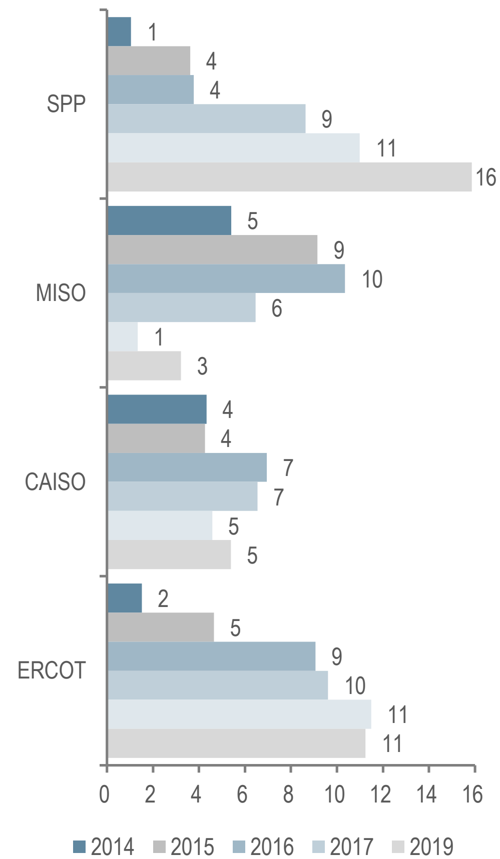
- Lithium-ion technology has proven to be a viable short-duration application, albeit its average cost does not decline at incremental durations past six hours as a result of the step cost structure of additional storage modules
- Increased renewable generation enhances the value of energy arbitrage 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
- As part of its Energy Transition Platform, California is specifying long-duration storage as a small, though critical, component of the 25 GW of renewable and storage target to be procured over the next 10 years
- Increasing occurrences of low or negative pricing has 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

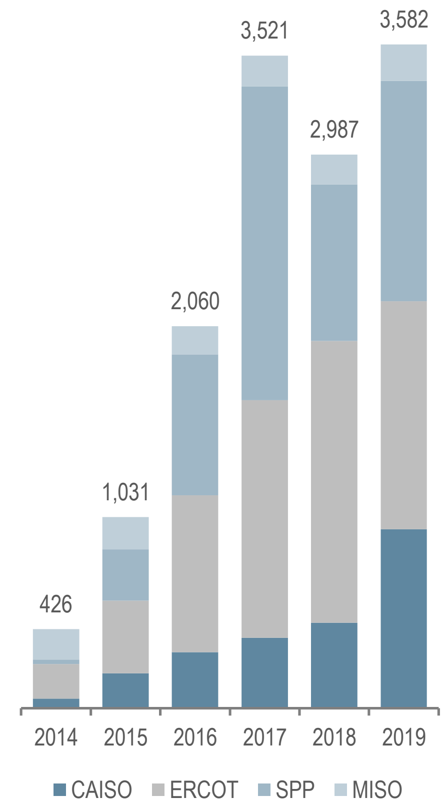
- **Flow:** 51 MWh grid-scale vanadium battery energy storage system for a wind farm in Asia
- **Thermal:** Two power plants (75 MWh and 115 MWh) deploying thermal storage in the Middle East
- **Mechanical:**
  - 15 MWh cryogenic energy storage demonstration plant in Europe
  - Three CAES projects in operation or under construction in North America and Australia

Grid Impacts of Increasing Renewable Energy Penetration

Selected ISO negative pricing behavior, 2014 – 2019
(% of hours <$10/MWh)



Selected ISO curtailments, 2014 – 2019 (GWh)



Source: *Green Tech Media, CPUC, CleanTech Group, Industry interviews, Lazard and Roland Berger.*

Illustrative Long-Duration Use Case(1)

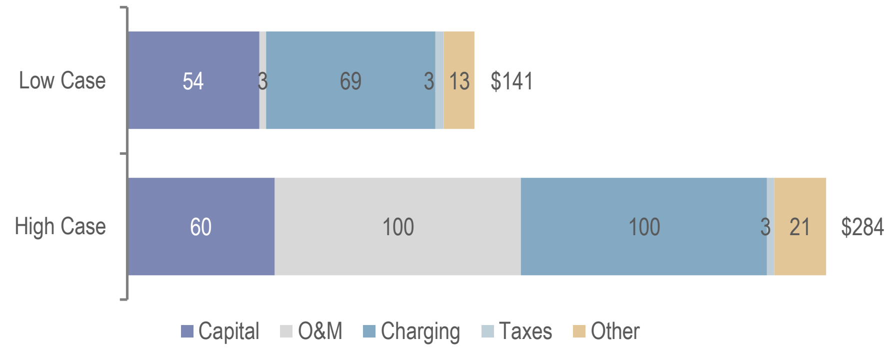
A levelized cost of storage analysis of an illustrative 100 MW / 1,000 MWh energy storage system yields potentially attractive economics relative to the available alternatives

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, 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 (i.e., Vanadium, Zinc Bromine and Copper Zinc), 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)***		***$140***	***$140***	***$140***	***$140***	***$140***	***$140***
Total Revenues	**(B) x (C) = (D)***		**$9.7**	**$9.4**	**$9.2**	**$8.9**	**$8.7**	**$7.0**
Total Charging Cost [3]	(E)		($2.5)	($2.5)	($2.4)	($2.4)	($2.4)	($2.5)
Total O&M [4]	(F)*		(0.8)	(0.8)	(1.0)	(1.0)	(1.0)	(1.2)
Total Operating Costs	**(E) + (F) = (G)**		($3.3)	($3.3)	($3.5)	($3.5)	($3.5)	($3.8)
EBITDA	**(D) - (G) = (H)**		**$6.4**	**$6.2**	**$5.7**	**$5.5**	**$5.3**	**$3.2**
Debt Outstanding - Beginning of Period	(I)		$8.1	$7.9	$7.7	$7.5	$7.3	$0.8
Debt - Interest Expense	(J)		(0.6)	(0.6)	(0.6)	(0.6)	(0.6)	(0.1)
Debt - Principal Payment	(K)		(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.8)
Levelized Debt Service	(J) + (K) = (L)		(0.8)	(0.8)	(0.8)	(0.8)	(0.8)	(0.8)
EBITDA	**(H)**		$6.4	$6.2	$5.7	$5.5	$5.3	$3.2
Depreciation (7-yr MACRS)	(M)		(5.8)	(9.9)	(7.1)	(5.0)	(3.6)	0.0
Interest Expense	(J)		(0.6)	(0.6)	(0.6)	(0.6)	(0.6)	(0.1)
Taxable Income	**(H) + (M) + (J) = (N)**		**($0.0)**	**($4.4)**	**($2.0)**	**($0.2)**	**$1.1**	**$3.1**
Tax Benefit (Liability)	**(N) x (Tax Rate) = (O)**		**$0.0**	**$0.9**	**$0.4**	**$0.0**	**($0.2)**	**($0.7)**
After-Tax Net Equity Cash Flow	**(H) + (L) + (O) = (P)**	**($32.3)** [7]	**$5.6**	**$5.9**	**$5.2**	**$4.6**	**$4.2**	**$1.7**

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]	$202
O&M, Warranty & Augmentation Cost ($/MWh)	$14
Charging Cost ($/kWh)	$0.031
Charging Cost Escalator (%)	1.87%
Efficiency (%)	85%

■ 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 ($1.91/kWh, plus relevant Solar PV O&M, escalating annually at 2.5%), augmentation costs (1.2% of ESS equipment) and warranty costs (0.6% 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 $50.60/kW, Module cost of $136.00/kWh, Balance of System cost of $28.23/kWh and a 6.5% engineering procurement and construction ("EPC") cost.
(7) Reflects initial cash outflow from equity sponsor.

Levelized Cost of Storage—Key Assumptions

	Units	Wholesale (Standalone)			Transmission & Distribution	Utility-Scale (PV + Storage)	Commercial & Industrial (Standalone)	Commercial & Industrial (PV + Storage)	Residential (PV + Storage)
		(100 MW / 100 MWh)	(100 MW / 200 MWh)	(100 MW / 400 MWh)	(10 MW / 60 MWh)	(50 MW / 200 MWh)	(1 MW / 2 MWh)	(0.5 MW / 2 MWh)	(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
100% Depth of 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	247,470	0	1,730	13
Project Life	Years	20	20	20	20	20	10	20	20
Memo: Annual Used Energy	*MWh*	*35,000*	*70,000*	*140,000*	*1,500*	*70,000*	*500*	*700*	*9*
Memo: Project Used Energy	*MWh*	*700,000*	*1,400,000*	*2,800,000*	*30,000*	*1,400,000*	*5,000*	*14,000*	*175*
Initial Capital Cost—DC	$/kWh	$176 – $271	$164 – $295	$164 – $309	$271 – $313	$181 – $475	$319 – $400	$319 – $575	$350 – $833
Initial Capital Cost—AC	$/kW	$50 – $65	$51 – $71	$51 – $80	$80 – $80	$64 – $102	$56 – $67	$56 – $171	$170 – $263
EPC Costs	$	$2 – $5	$2 – $9	$2 – $18	$1 – $4	$5 – $10	$0 – $0	$0 – $0	$0 – $0
Solar PV Capital Cost	$/kW	$0 – $0	$0 – $0	$0 – $0	$0 – $0	$900 – $900	$0 – $0	$2,225 – $2,225	$2,675 – $2,675
Total Initial Installed Cost	$	$25 – $38	$40 – $75	$73 – $149	$18 – $23	$138 – $205	$1 – $1	$3 – $4	$0 – $0
O&M	$/kWh	$2.0 – $4.0	$1.9 – $2.4	$1.8 – $2.2	$1.3 – $1.3	$2.7 – $11.9	$2.0 – $3.7	$0.4 – $15.8	$0.0 – $0.0
Extended Warranty Start	Year	3	3	3	3	3	3	3	3
Warranty Expense % of Capital Costs	%	0.56% – 1.13%	0.56% – 1.13%	0.56% – 1.13%	0.92% – 0.28%	1.00% – 1.18%	0.75% – 1.50%	0.96% – 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	$29	$31	$32	$36	$0	$101	$0	$0
Charging Cost Escalator	%	1.87%	1.87%	1.87%	1.87%	0.00%	2.16%	0.00%	0.00%
Efficiency of Storage Technology	%	85% – 93%	85% – 93%	85% – 93%	83% – 83%	80% – 85%	94% – 94%	80% – 80%	85% – 97%
Levelized Cost of Storage	$/MWh	$158 – $250	$140 – $243	$132 – $245	$2,025 – $2,771	$81 – $124	$432 – $590	$247 – $319	$406 – $506

Source: *Lazard and Roland Berger estimates.*

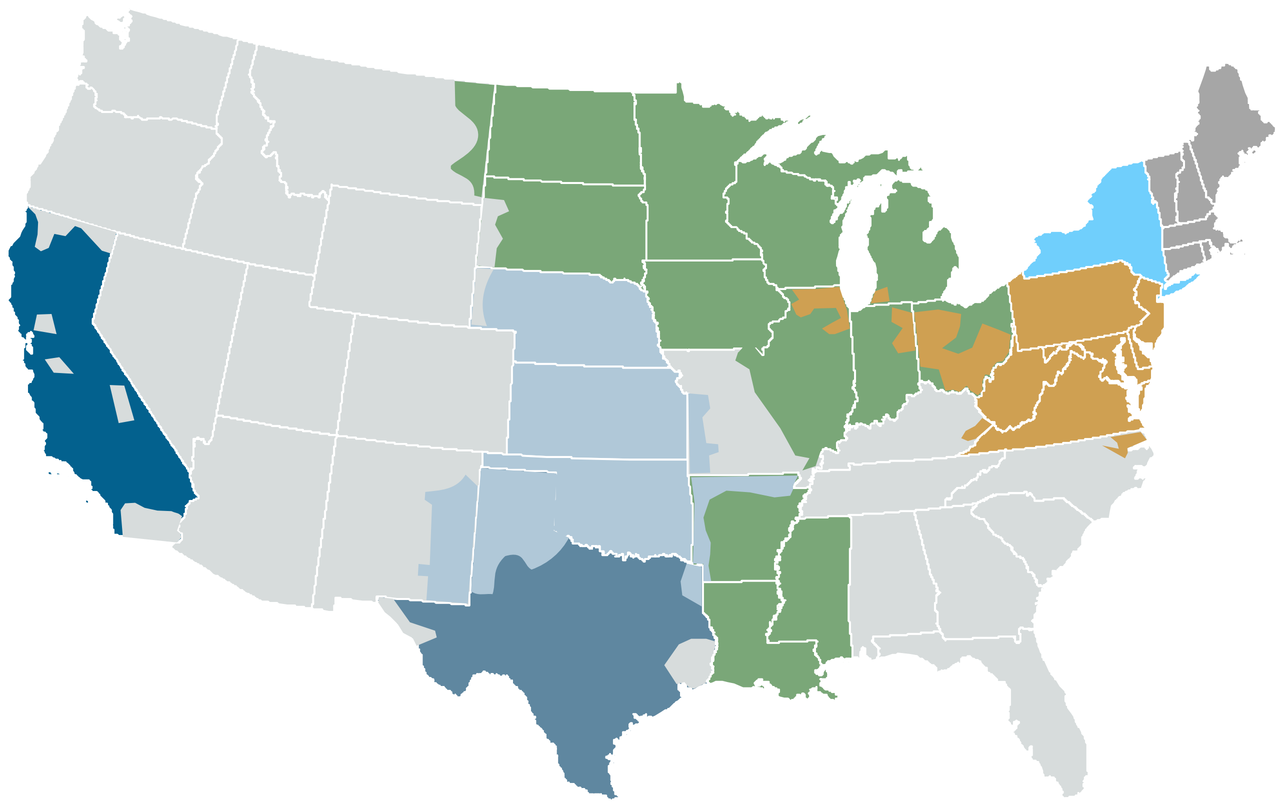
Note: Assumed capital structure of 80% equity (with a 12% cost of equity) and 20% debt (with an 8% cost of debt). Capital cost units are the total investment divided by the storage equipment's energy capacity (kWh rating) and inverter rating (kW rating). Wholesale and Transmission & Distribution charging costs use the EIA's "2019 Wholesale Price $/MWh– Wtd Avg Low" price estimate of $35.56/MWh. Escalation is derived from the EIA's "AEO 2018 Energy Source–Electric Price Forecast (10-year CAGR)" and ranges from 1.87% – 2.16% by use case. Storage systems paired with Solar PV do not charge from the grid.

B Value Snapshot Case Studies

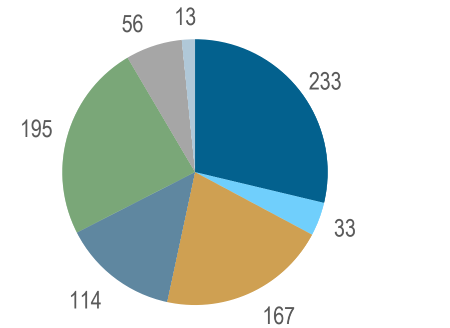
1 Value Snapshot Case Studies—U.S.

U.S. Energy Storage Capacity by ISO

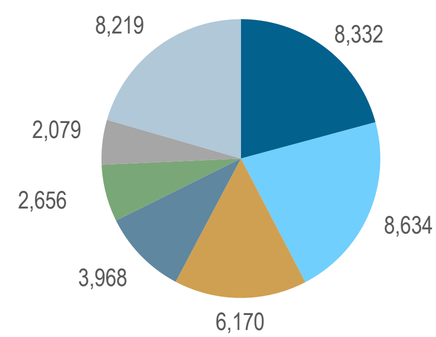
ISOs across the U.S.[(1)], led by CAISO and the NY-ISO, are anticipating significant growth in battery storage deployment over the next decade



Installed and Operating U.S. Storage Capacity[(2)] (MW)



Storage in Interconnection Queue[(3)] (MW)



Source: EIA, ISO databases, Lazard and Roland Berger.

(1) Excludes the SERC Reliability Corporation ("SERC") and Western Electricity Coordinating Council ("WECC") outside of CAISO.

(2) Front-of-the-Meter ("FTM"), utility-scale storage in 2019.

(3) Interconnection data as of June 2020 for the next ~10 years, including projects that have been added to the ISO queue in 2017 or later. Note that a significant portion of storage in a given interconnection queue is generally not built due to natural attrition.

1 Wholesale, CAISO (Los Angeles, California)

($ in thousands, unless otherwise noted)

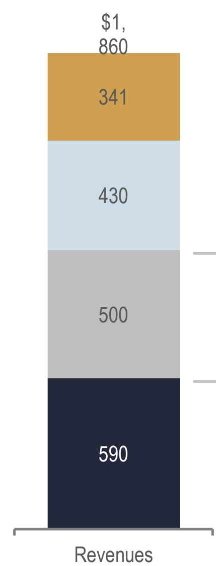
50 MW / 200 MWh Standalone Battery

- **Project IRR: 23.3%[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 $31.55/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 Resource Adequacy (“RA”) parameters
  - To maximize additional revenues, the battery optimally allocates itself to Frequency Regulation and Spin/Non-Spin based on current market pricing
- **Market observations:**
  - Utilities continue to procure storage capacity to meet California’s current 1.3 GW storage mandate
  - Community Choice Aggregators (“CCAs”) are also procuring storage to meet local capacity requirements and to balance renewable energy generation
  - Current Resource Adequacy prices can range from $1 – $10+/ kW-month, though prices are generally declining due to expectations that required duration for RA services will increase
    - Contracts are typically negotiated on a bilateral basis, with local grid conditions driving variation in terms
    - Advantageous pricing terms have been observed for projects physically located in San Francisco or Los Angeles
  - 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
    - Investors are becoming more comfortable with energy arbitrage as a bankable revenue stream as a result of persistent market volatility

Value Snapshot Revenues[1]



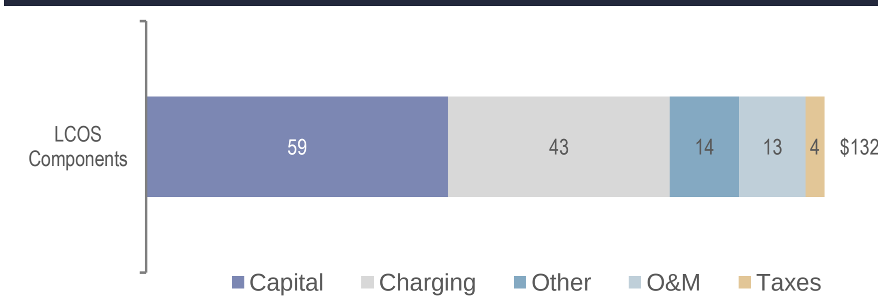
Spin/Non-Spin Reserves
- $7.00/MWh
- Deployed 36% of the time[2]
- 63% correlated to energy price movements

Frequency Regulation
- $10.95/MWh (up), $10.34/MWh (down)
- Up and down dispatch is 62% correlated to energy prices
- Deployed 51% of the time[2]

Energy Arbitrage
- Median dispatch price: $88/MWh (range of $10/MWh to over $1,000/MWh)
- Median charging is $29/MWh
- Deployed 5% of the time[2]

Resource Adequacy
- 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 2021.

(1) NPV of lifetime project revenues is presented. Cost structure representative of the “Low 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.

2 T&D Deferral, ISO-NE (Nantucket, Massachusetts)

($ in thousands, unless otherwise noted)

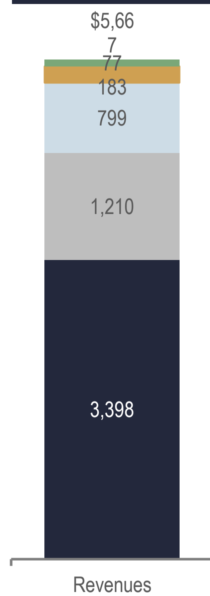
6 MW / 48 MWh Standalone Battery

- **Project IRR: 8.1%[(1)]**

Use Case Commentary

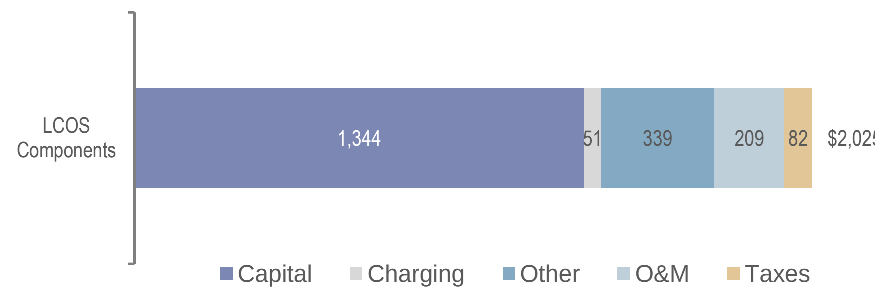
- **Additional use case context:**
  - T&D deferral Value Snapshot is based on real project cost and revenue data in ISO-NE for a project that reached commercial operation in 2019
  - The battery charges at an average of $31.98/MWh
  - Nantucket's population increases more than 5x in the summer and the island's transmission cables will soon be unable to support the peak load during N-1 contingency events (i.e., events in the grid that result in the loss of function of generator or transmission components)
  - In lieu of additional transmission capacity, the storage project provides supply to meet increased electricity demand during summer peak months
- **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
  - Utility-owned T&D use cases typically satisfy one of the following conditions:
    - A state mandate exists explicitly requiring the deployment of storage for T&D use cases, (e.g., Massachusetts and New York)
    - New contract types are being utilized (e.g., T&D Power Purchase Agreements ("PPAs") in Rhode Island)

Value Snapshot Revenues[(1)(2)]



Market participation (Frequency Regulation, Demand Response, Spinning Reserve, Capacity)	• In addition to the value of the transmission deferral, there is additional upside through ISO-NE market participation in ancillary services • The battery participates in market services during off-peak months and when N-1 contingency events are not anticipated
Transmission Deferral	• Installing battery storage allowed the utility to defer investment in new underwater transmission cables with expected costs exceeding $105 million

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



Source: U.S. Department of Energy, Pacific Northwest National Lab, EIA, Industry interviews, Lazard and Roland Berger.

Note: LCOS data reflects 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 Snapshot analysis correspond to parameters unique to the project analyzed.

(1) NPV of lifetime project revenues is presented. Cost structure representative of the "Low 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 Utility-Scale PV+Storage, ERCOT (Corpus Christi, Texas)

($ in thousands, unless otherwise noted)

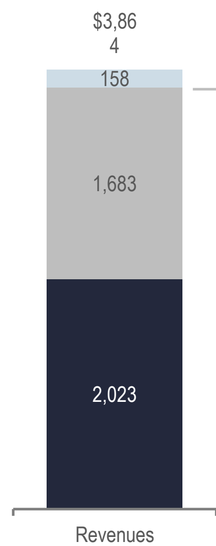
50 MW / 200 MWh Battery, paired with 100 MW of Solar PV

- **Project IRR: 22.3%[1]**

Use Case Commentary

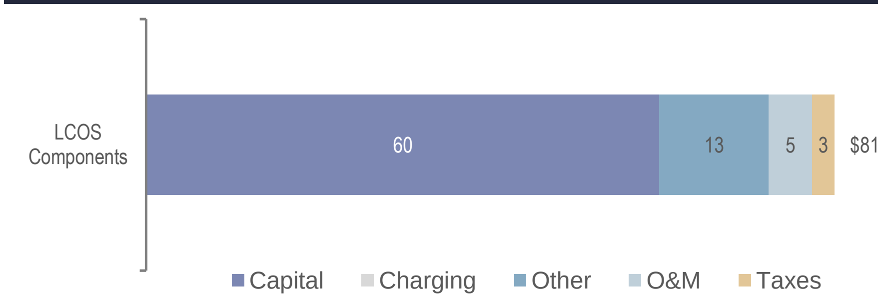
- **Additional use case context:**
  - The project utilizes an AC-coupled battery at a node in South Texas
  - The battery charges exclusively from the coupled solar PV system for the first five years of operation in order to maintain eligibility for the Federal Solar Investment Tax Credit ("ITC")
- **Market observations:**
  - Existing transmission interconnections at operating generation plants may streamline hybrid energy storage use cases in ERCOT
  - As of June 2020, ~50% of ERCOT's current ~7.2 GW battery interconnection queue is composed of PV+Storage projects
  - Investors are becoming more comfortable with energy arbitrage as a bankable revenue stream as a result of persistent market volatility
  - Price spikes during summer months as a result of weather and tight reserve margins is seen by many developers as sufficient to make projects economically viable
  - 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
  - ERCOT is following a process similar to that of FERC with respect to establishing regulations to accelerate the integration of battery storage
    - ERCOT's Battery Energy Storage Task Force ("BESTF") launched in October 2019 with the objective of developing shorter- and longer-term participation models for both hybrid and standalone resources

Value Snapshot Revenues[1]



Frequency Regulation ("FR")	• $23.31 (up), $8.02 (down)/MWh • Deployed 31% of the time[2] • FR up and down are correlated and somewhat correlated to energy price (43% and 99%, respectively)
Energy Arbitrage	• Median dispatch price: $30/MWh (range of $5 to over $5,000/MWh) • Deployed 50% of the time[2]
Spin/Non-Spin Reserves	• $29.38/MWh • Deployed 82% 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 2021.

(1) NPV of lifetime project revenues is presented. Cost structure representative of the "Low 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)

($ in thousands, unless otherwise noted)

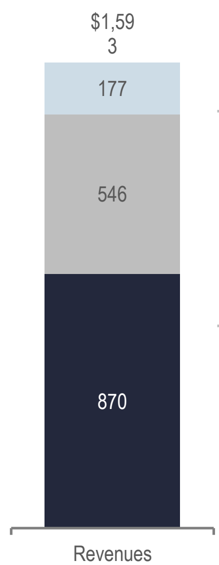
1 MW / 2 MWh Battery

- **Project IRR: 33.7%[(1)]**

Use Case Commentary

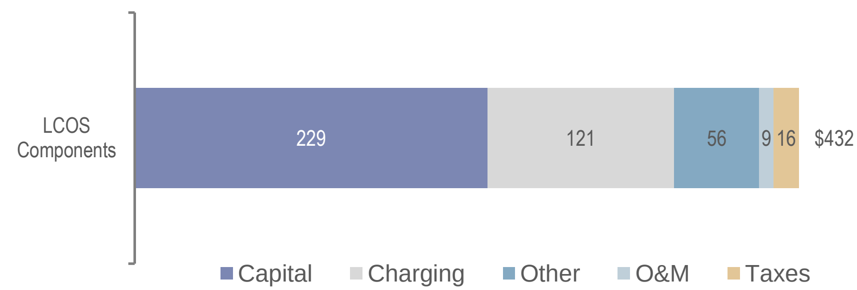
- **Additional use case context:**
  - The project utilizes an AC-coupled battery and the load shape of a large office building in San Francisco
  - Charging costs are an average of $100.65/MWh, reflecting the local TOU rate
  - The project is developed to reduce energy load during periods of peak pricing, 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:**
  - Many developers are moving 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
  - SGIP funding: As of August 2020, ~44% of the funds allocated to large-scale storage projects remain available
  - 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
  - Strategically located C&I batteries in California (e.g., San Francisco and Los Angeles) have the potential to receive additional Resource Adequacy payments

Value Snapshot Revenues[(1)]



Demand Response—Utility	• Fixed annual payment of $32.59/kW-year
Local Incentive Payments	• PG&E's SGIP incentives for commercial building use cases is $350,000/MWh
Bill Management	• The project participates in PG&E's E-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 2021.
(1) NPV of lifetime project revenues is presented. Cost structure representative of the "Low Case" is used in the IRR analysis and shown in the LCOS summary.

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

($ in thousands, unless otherwise noted)

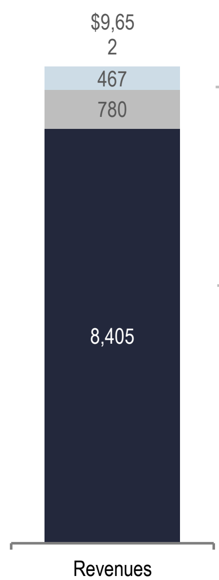
0.5 MW / 2 MWh Battery, paired with 1 MW of Solar PV

- **Project IRR: 26.2%(1)**

Use Case Commentary

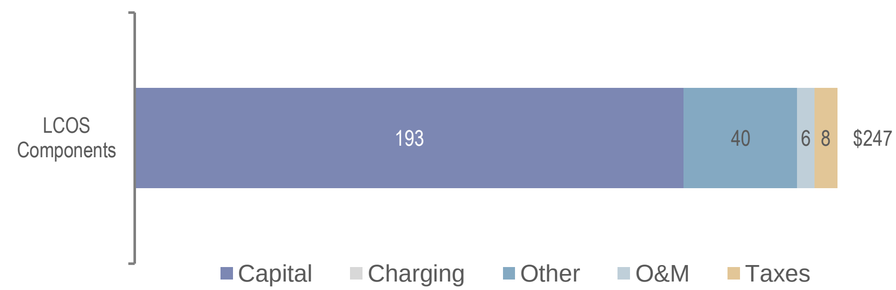
- **Additional use case context:**
  - The project utilizes a DC-coupled battery and the load shape of a large office building in San Francisco
  - The battery charges exclusively from the coupled solar PV system for the first five years of operation in order to maintain eligibility for the ITC
  - The 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:**
  - Many developers are moving 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
  - SGIP funding: As of August 2020, ~44% of the funds allocated to large-scale storage projects remain available
  - The value of selling excess solar generation back to the grid (i.e., net metering) is declining as pricing declines during hours of peak solar production
  - Strategically located C&I batteries in California (e.g., San Francisco and Los Angeles) have the potential to receive additional Resource Adequacy payments
  - 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)



Demand Response—Utility	•	Flat yearly payment worth $32.39/kW-year for this specific project size and location
Local Incentive Payments	•	PG&E's SGIP incentives for this project type (commercial building paired with solar, receiving the ITC) valued at $250,000/MWh
Bill Management	•	The system participates in PG&E's E-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 2021.
(1) NPV of lifetime project revenues is presented. Cost structure representative of the "Low Case" is used in the IRR analysis and shown in the LCOS summary.

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

($ in thousands, unless otherwise noted)

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

- **Project IRR: 14.9%[(1)]**

Use Case Commentary

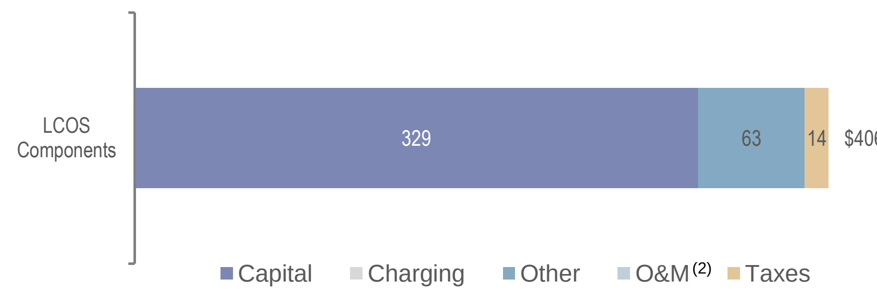
- **Additional use case context:**
  - The project utilizes a AC-coupled battery and the load shape of a large single-family residence in Hawaii
  - The battery charges exclusively from the coupled solar PV system for the first five years of operation in order to maintain eligibility for the ITC
  - 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 such that the new tariffs reflected customer credits based on avoided variable generation costs for HECO, rather than the retail rate, significantly reducing attractiveness of standalone PV
      - This change in turn enhanced the economics for energy storage, as customers were able to shift excess energy production to peak hours
- **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

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 TOU-R Tariff (2019 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 2021.
(1) NPV of lifetime project revenues is presented. Cost structure representative of the "Low 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.

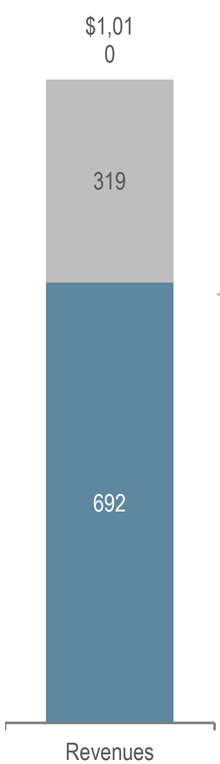
2 Value Snapshot Case Studies—International

International Value Snapshots

($ in thousands, unless otherwise noted)

1 Wholesale, Germany (Bavaria)[(1)]

- **50 MW / 200 MWh standalone battery**
  - Project IRR: 4.3%[(1)]



Frequency Regulation

- Average estimated unit prices for Frequency Response sub-classes, 2021:
  - FCR Capacity payments: $35.25/MW (up & down)
  - aFRR Capacity payments: $6.64/MW up, $7.40/MW down
  - mFRR Capacity payments: $22.49/MW up, $12.65/MW down
- Assumes 0.2% probability to be called on for energy participation

Energy Arbitrage

- Median energy arbitrage price, 2021: $48.91/MWh
  - Range of $0/MWh – $103/MWh
- Median charging price, 2021: ~$27/MWh

3 Utility-Scale PV+Storage, Australia (Queensland)[(1)]

- **50 MW / 200 MWh battery paired with 100 MW of Solar PV**
  - Project IRR: 11.9%[(1)]

Frequency Regulation

- Average estimated unit price, 2021:
  - $14/MW (up & down)

Resource Adequacy

- Average estimated unit price, 2021:
  - $377/MW-year

Energy Arbitrage

- Median energy arbitrage price, 2021: ~$52/MWh
  - Range of $23/MWh – $1,561/MWh

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

Note: Detailed LCOS and market information not collected for international cases. All figures presented in USD using the following exchange rates: U.S.$0.699/AUD, U.S.$0.741/CAD and U.S.$1.136/EUR. International cases use same beginning capital structure as domestic cases and are adjusted for regional differences in items such as EPC, BOS and charging costs.

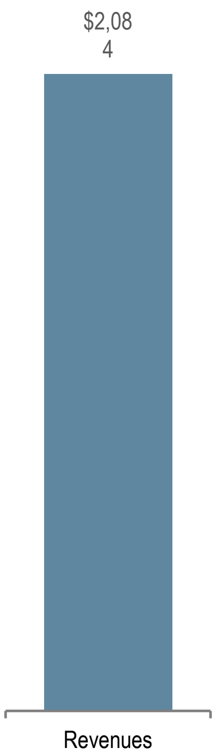
(1) NPV of lifetime project revenues is presented. Cost structure representative of the "Low Case" is used in the IRR analysis.

International Value Snapshots (cont'd)

($ in thousands, unless otherwise noted)

4 C&I Standalone, Canada (Ontario)

- **1 MW / 2 MWh standalone battery**
  - Project IRR: 13.1%(1)

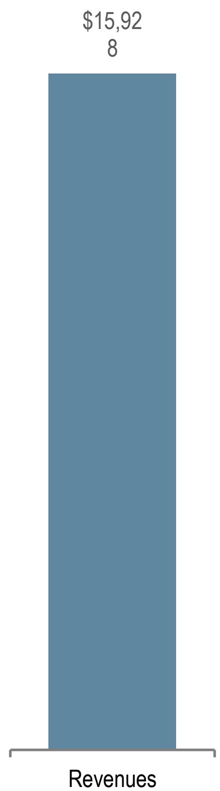


Bill Management

- Participates exclusively in Ontario IESO's Global Adjustment savings
  - Requires exact timing and participation in 5 – 10 peak load days per year
  - Savings occur by avoiding peak global adjustment charges
- Value Snapshot methodology assumes participation in five peak load days per year

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

- **0.5 MW / 2 MWh battery paired with 1 MW of Solar PV**
  - Project IRR: 28.0%(1)

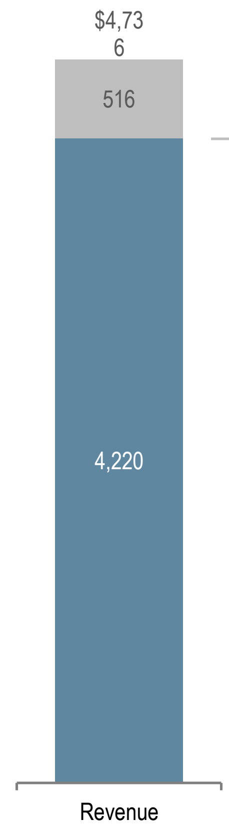


Bill Management

- Participation in AusNet's NSP56 Tariff structure

6 Residential PV+Storage, Germany (Bavaria)

- **0.006 MW / 0.025 MWh battery paired with 0.1 MW of Solar PV**
  - Project IRR: 4.4%(1)



Local Incentive Payments

- Participation in Germany's home PV+storage incentive program

Bill Management

- Assumes average residential retail electricity price of $346/MWh

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

Note: Detailed LCOS and market information not collected for international cases. All figures presented in USD using the following exchange rates: U.S.$0.699/AUD, U.S.$0.741/CAD and U.S.$1.136/EUR. International cases use same beginning capital structure as domestic cases and are adjusted for regional differences in items such as EPC, BOS and charging costs.

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

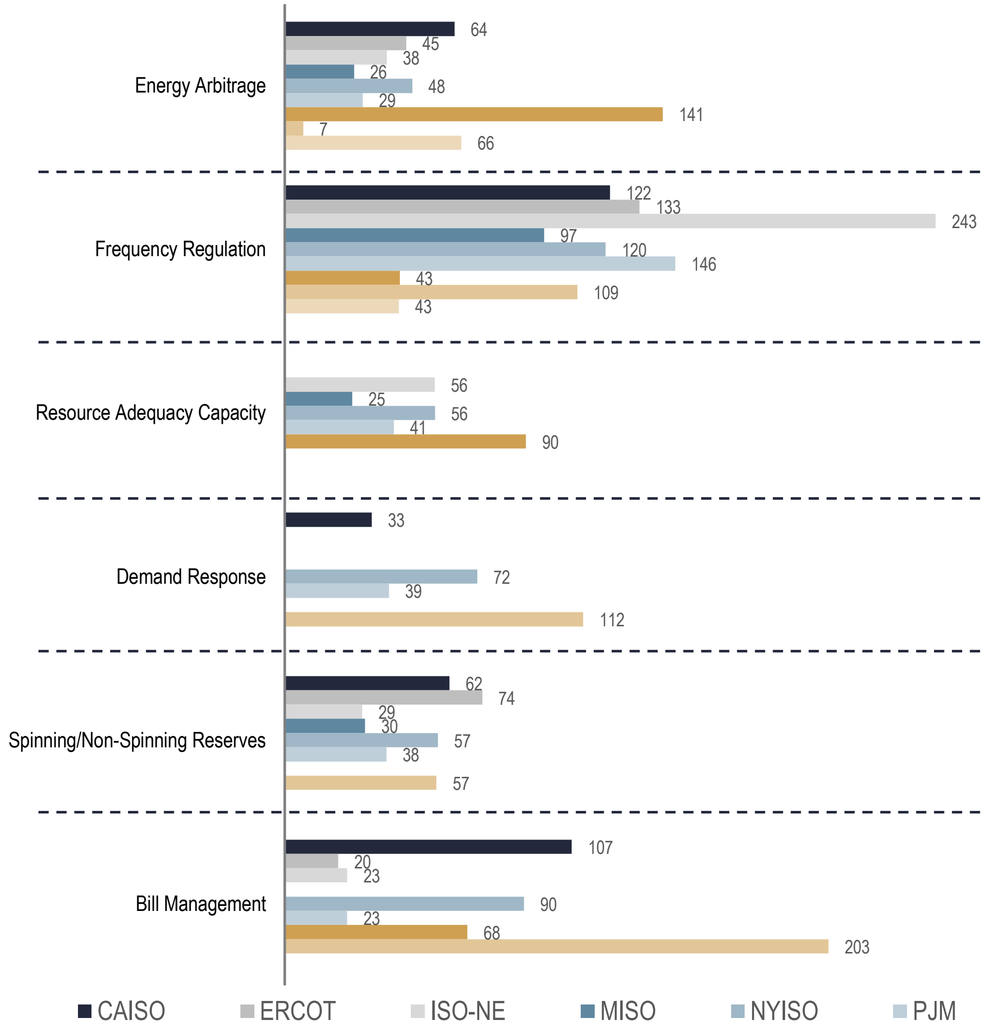
C Supplemental Value Snapshot Analysis Materials

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 in front-of-the-meter ("FTM") and behind-the-meter ("BTM") revenue streams from currently deployed energy storage systems(1)

Revenue Streams(2)



Observations

- CAISO and ERCOT have highest energy arbitrage revenue streams in the U.S., reflecting the "duck-curve" and periodic price-spikes, respectively
- The lack of regional interconnection of Australia's electric systems is apparent based on the arbitrage opportunities in Victoria and Queensland
- While potentially attractive, frequency regulation markets lack depth and risk being saturated as additional resources enter the market
- ISO-NE shows the most potential for frequency regulation of markets surveyed
- Resource adequacy 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)
- Limited opportunity for DR revenue streams beyond Ontario IESO, PJM, NY-ISO and Australia
- Value of demand response in Ontario IESO driven by Global Adjustment Charge ("GAC") where timing system peak is crucial for project economics
- Hybrid resources in California (e.g., solar plus gas-fired generators) utilize these markets in addition to RA values to enhance project economics
- ERCOT, NY-ISO and ERCOT are the highest potential markets in the U.S.
- Ontario IESO's GAC continues to be the BTM use case with the most attractive opportunity in North America
- Limited opportunity for material revenue streams in the U.S. outside of California

Source: *Enovation Analytics, Lazard and Roland Berger estimates.*
Note: All figures presented in USD using the following exchange rates: U.S.$0.699/AUD, U.S.$0.741/CAD and U.S.$1.136/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.

Illustrative U.S. Value Snapshots—Assumptions

	Revenue Source	Description	Average Modeled Price	Annual Revenue ($/kW-year)[1]	Cost Assumptions
1 Wholesale[2] CAISO	**Energy Arbitrage**	• Energy prices based on 2019 CAISO nodal price in SP15 • Annual escalation of 1.8%	$45.83/MWh	$56	• AC system: $13/kWh • DC system: $164/kWh • EPC: 3.5% • Efficiency: 85% • Augmentation costs: 1.2% of ESS
	Frequency Regulation	• Includes Reg-Up and Reg-Down products; participation based on hourly price and battery state of charge	Reg Up: $10.95/MWh Reg Down: $10.34/MWh	$66	
	Spinning Reserve	• Spinning Reserves based on 2019 CAISO nodal price in SP15	$7.00/MWh	$39	
	Resource Adequacy	• Assumes participation in Southern California Edison's Local Capacity Resource programs • Reliability ($/kW-month) payment amounts vary by contract and are not publicly available • Estimates assume a modified Net CONE methodology based on assumed technology costs and other available revenue sources	$6.25/kW-month	$75	
2 Transmission and Distribution ISO-NE	**Transmission Deferral**	• Installing battery storage allowed the utility to defer investment into new underwater transmission cables with expected up-front costs of over $105 million • Traditional solution cost is amortized over 20 years	Traditional upgrade: >$105 million	$439	• AC system: $37/kWh • DC system: $446/kWh • EPC: 43% • Efficiency: 83% • Augmentation costs: 1.2% of ESS
	Ancillary services	• Battery participates in market services during off-peak months and when N-1 contingency events are not anticipated	Participation in: Frequency Regulation, DR, Spin/Non-Spin, Capacity	$270	
3 Wholesale (PV+Storage)[3] ERCOT	**Energy Arbitrage**	• Energy prices based on 2018 ERCOT South real time • Annual escalation of 2%	$41.72/MWh	$183	• AC system: $16/kWh • DC system: $181/kWh • EPC: 11.2% • Efficiency: 85% • Augmentation costs: 1.2% of ESS
	Frequency Regulation	• Includes Reg-Up and Reg-Down products (Reg-Down eligible after year 6); participation based on hourly price and battery state of charge	Reg Up: $23.31/MWh Reg Down: $8.02/MWh	$20	
	Spinning Reserve	• ERCOT responsive reserve product; participation based on hourly price and battery state of charge	$29.38/MWh	$251	

Source: Industry interviews, ISO/RTO markets, U.S. Department of Energy, Lazard and Roland Berger estimates.
Note: Capital cost units are the total investment divided by the storage equipment's energy capacity (kWh rating) and inverter rating (kW rating).
(1) Revenue based on installed capacity (kW).
(2) Information presented is specific to case with 4 hours of installed storage duration.
(3) Project qualifies for the ITC.

Illustrative U.S. Value Snapshots—Assumptions (cont'd)

	Revenue Source	Description	Average Modeled Price	Annual Revenue ($/kW-year)[1]	Cost Assumptions
4 Commercial & Industrial (Standalone)[2] California, PG&E	Demand Bidding Program	• Year-round, event-based program; credited for 50% – 200% of event performance; no underperformance penalties	$32.59/kW-year	$33	• AC system: $28/kWh • DC system: $319/kWh • EPC: 14.8% • Efficiency: 94% • Augmentation costs: None
	Bill Management	• Reduction of demand and energy charges through load shifting • Modeled based on PG&E's E-20 TOU tariff • Annual escalation of 2.5%	PG&E E-20 TOU Tariff	$133	
5 Commercial & Industrial (PV+Storage)[2][3] California, PG&E	Demand Bidding Program	• Year-round, event-based program; credited for 50% – 200% of event performance; no underperformance penalties	$32.39/kW-year	$65	• AC system: $14/kWh • DC system: $319/kWh • EPC: 15.0% • Efficiency: 85% • Augmentation costs: 1.3% of ESS
	Bill Management	• Reduction of demand and energy charges through load shifting • Modeled based on PG&E's E-20 TOU tariff • Annual escalation of 2.5%	PG&E E-20 TOU Tariff	$903*	
6 Residential (PV+Storage)[3] Hawaii, HECO	Bill Management	• Reduction of energy charges through load shifting • Modeled based on HECO's TOU-R (5pm – 10pm Peak) rate • Annual escalation of 2.5%	HECO TOU-R (5pm – 10pm Peak) Tariff	$776*	• AC system: $41/kWh • DC system: $350/kWh • EPC: 18.3% • Efficiency: 90% • Augmentation costs: None

Source: *Industry interviews ISO/RTO markets, U.S. Department of Energy, Lazard and Roland Berger estimates.*
* Calculated including net metering benefits from the solar PV system.
Note: Capital cost units are calculated as the total investment divided by the storage equipment's energy capacity (kWh rating) and inverter rating (kW rating).
(1) Revenue based on installed capacity (kW).
(2) Project also participates in the SGIP incentive program.
(3) Project qualifies for the ITC.

Illustrative International Value Snapshots—Assumptions

	Revenue Source	Description	Average Modeled Price	Annual Revenue ($/kW-year)(1)	Cost Assumptions
1 Wholesale Germany, EEX/Tennet	Energy Arbitrage	• Energy prices based on 2019 – 2020 day-ahead prices (operating within the Tennet TSO) • Annual escalation of 4.3%	$48.91/MWh	$66	• AC system: $13/kWh • DC system: $164/kWh • EPC: 3.5% • Efficiency: 85% • Augmentation costs: 1.2% of ESS
	Frequency Regulation	• Includes Reg-Up and Reg-Down products; participation based on pricing for 4-hour blocks • No participation in aFRR classes	See Value Snapshot for price details	$33	
2 Transmission and Distribution(2)	--	--	--	--	--
3 Wholesale (PV+Storage) Australia, NEM	Energy Arbitrage	• Energy prices based on 2019/2020 Queensland region • Assume discharge of battery in top four hours of each day • Annual escalation of 4.0%	Hourly LMP	$306*	• AC system: $18/kWh • DC system: $206/kWh • EPC: 11.4% • Efficiency: 85% • Augmentation costs: 1.2% of ESS
	Ancillary Services	• Participation in Queensland ancillaries (Lower & Raise, 6sec, 5min, Reg, Restart, Reactive)	$14.33/MW	$43	
	Capacity	• Benchmark Reserve Capacity Price from AEMO • Annual escalation of (1.5%)	$377/kW-year	$90	
4 Commercial & Industrial (Standalone) Canada, IESO	Bill Management	• Ontario/IESO "Class B" GAC • Annual escalation of 4.0%	$370	$203	• AC system: $28/kWh • DC system: $412/kWh • EPC: 14.8% • Efficiency: 94% • Augmentation costs: None
5 Commercial & Industrial (PV+Storage) Australia, AusNet	Bill Management	• AusNet utility in Victoria, Australia • Reduction of demand and energy charges through load shifting • Modeled based on NSP56 rate	AusNet NSP56 Tariff	$1,437*	• AC system: $16/kWh • DC system: $362/kWh • EPC: 15.2% • Efficiency: 85% • Augmentation costs: 1.3% of ESS
6 Residential (PV+Storage) Germany, SWM	Local Incentive Program	• German Development Bank, KfW Incentive program	10% of Capex	$456*	• AC system: $46/kWh • DC system: $397/kWh • EPC: 18.5% • Efficiency: 85% • Augmentation costs: None
	Bill Management	• Reduction of energy charges through load shifting • German residential rate is from BDEW (Bundesverband der Energie-und Wasserwirtschaft) • Annual escalation of 2.5%	Retail Electric Rate: $0.30/kWh	$574*	

Source: *Lazard and Roland Berger estimates.*

Note: Capital cost units are calculated as the total investment divided by the storage equipment's energy capacity (kWh rating) and inverter rating (kW rating). All figures presented in USD using the following exchange rates: U.S.$0.699/AUD, U.S.$0.741/CAD and U.S.$1.136/EUR.

(1) Revenue based on installed capacity (kW).

(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.