EXH. RJB-7

DOCKET UE-230172

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DIRECT TESTIMONY AND EXHIBITS OF RONALD BINZ
ON BEHALF OF SIERRA CLUB

EXHIBIT RJB-7
LAZARD 2023 LEVELIZED COST OF ENERGY ANALYSIS

APRIL 2023

LCOE+

LAZARD

With support from Roland Berger

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I Lazard's Levelized Cost of Energy Analysis—Version 16.0

Introduction

Lazard's Levelized Cost of Energy ("LCOE") analysis addresses the following topics:

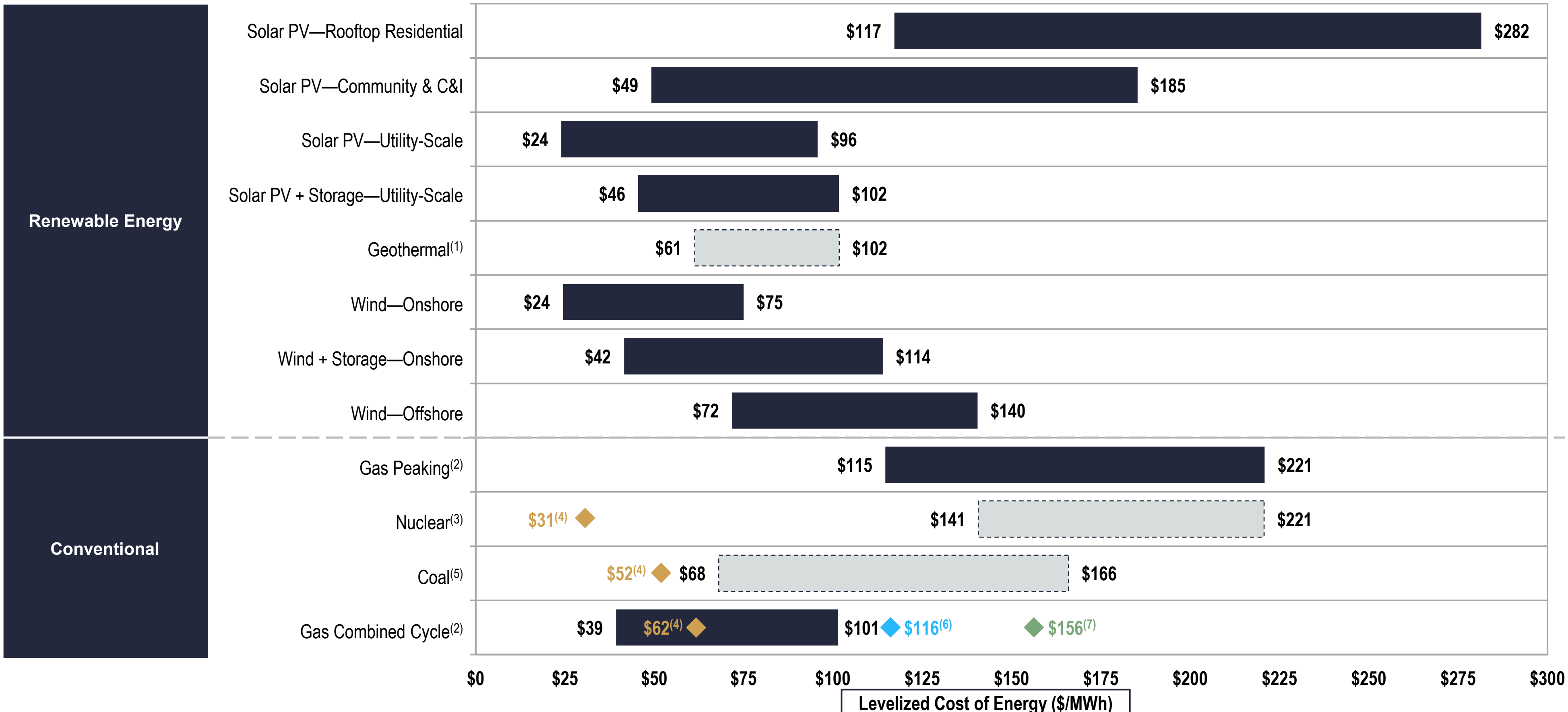
- **Comparative LCOE analysis for various generation technologies on a $/MWh basis, including sensitivities for U.S. federal tax subsidies, fuel prices, carbon pricing and cost of capital**
- **Illustration of how the LCOE of onshore wind, utility-scale solar and hybrid projects compare to the marginal cost of selected conventional generation technologies**
- **Illustration of how the LCOE of onshore wind, utility-scale solar and hybrid projects, plus the cost of firming intermittency in various regions, compares to the LCOE of selected conventional generation technologies**
- **Historical LCOE comparison of various utility-scale generation technologies**
- **Illustration of the historical LCOE declines for onshore wind and utility-scale solar technologies**
- **Comparison of capital costs on a $/kW basis for various generation technologies**
- **Deconstruction of the LCOE for various generation technologies by capital cost, fixed operations and maintenance ("O&M") expense, variable O&M expense and fuel cost**
- **Considerations regarding the operating characteristics and applications of various generation technologies**
- **Appendix materials, including:**
  - An overview of the methodology utilized to prepare Lazard's LCOE analysis
  - A summary of the assumptions utilized in Lazard's LCOE analysis

Other factors would also have a potentially significant effect on the results contained herein, but have not been examined in the scope of this current analysis. These additional factors, among others, could include: implementation and interpretation of the full scope of the Inflation Reduction Act ("IRA"); network upgrades, transmission, congestion or other integration-related costs; permitting or other development costs, unless otherwise noted; and costs of complying with various environmental regulations (e.g., carbon emissions offsets or emissions control systems). This analysis also does not address potential social and environmental externalities, including, for example, the social costs and rate consequences for those who cannot afford distributed generation solutions, as well as the long-term residual and societal consequences of various conventional generation technologies that are difficult to measure (e.g., nuclear waste disposal, airborne pollutants, greenhouse gases, etc.)

Note: This report has been compiled using U.S.-focused data.

Levelized Cost of Energy Comparison—Unsubsidized Analysis

Selected renewable energy generation technologies are cost-competitive with conventional generation technologies under certain circumstances



Source: Lazard and Roland Berger estimates and publicly available information.

Note: Here and throughout this presentation, unless otherwise indicated, the analysis assumes 60% debt at an 8% interest rate and 40% equity at a 12% cost. See page titled "Levelized Cost of Energy Comparison—Sensitivity to Cost of Capital" for cost of capital sensitivities.

(1) Given the limited data set available for new-build geothermal projects, the LCOE presented herein represents Lazard's LCOE v15.0 results adjusted for inflation.

(2) The fuel cost assumption for Lazard's unsubsidized analysis for gas-fired generation resources is $3.45/MMBTU for year-over-year comparison purposes. See page titled "Levelized Cost of Energy Comparison—Sensitivity to Fuel Prices" for fuel price sensitivities.

(3) Given the limited public and/or observable data set available for new-build nuclear projects and the emerging range of new nuclear generation strategies, the LCOE presented herein represents Lazard's LCOE v15.0 results adjusted for inflation (results are based on then-estimated costs of the Vogtle Plant and are U.S.-focused).

(4) Represents the midpoint of the unsubsidized marginal cost of operating fully depreciated gas combined cycle, coal and nuclear facilities, inclusive of decommissioning costs for nuclear facilities. Analysis assumes that the salvage value for a decommissioned gas combined cycle or coal asset is equivalent to its decommissioning and site restoration costs. Inputs are derived from a benchmark of operating gas combined cycle, coal and nuclear assets across the U.S. Capacity factors, fuel, variable and fixed operating expenses are based on upper- and lower-quartile estimates derived from Lazard's research. See page titled "Levelized Cost of Energy Comparison—Renewable Energy versus Marginal Cost of Selected Existing Conventional Generation Technologies" for additional details.

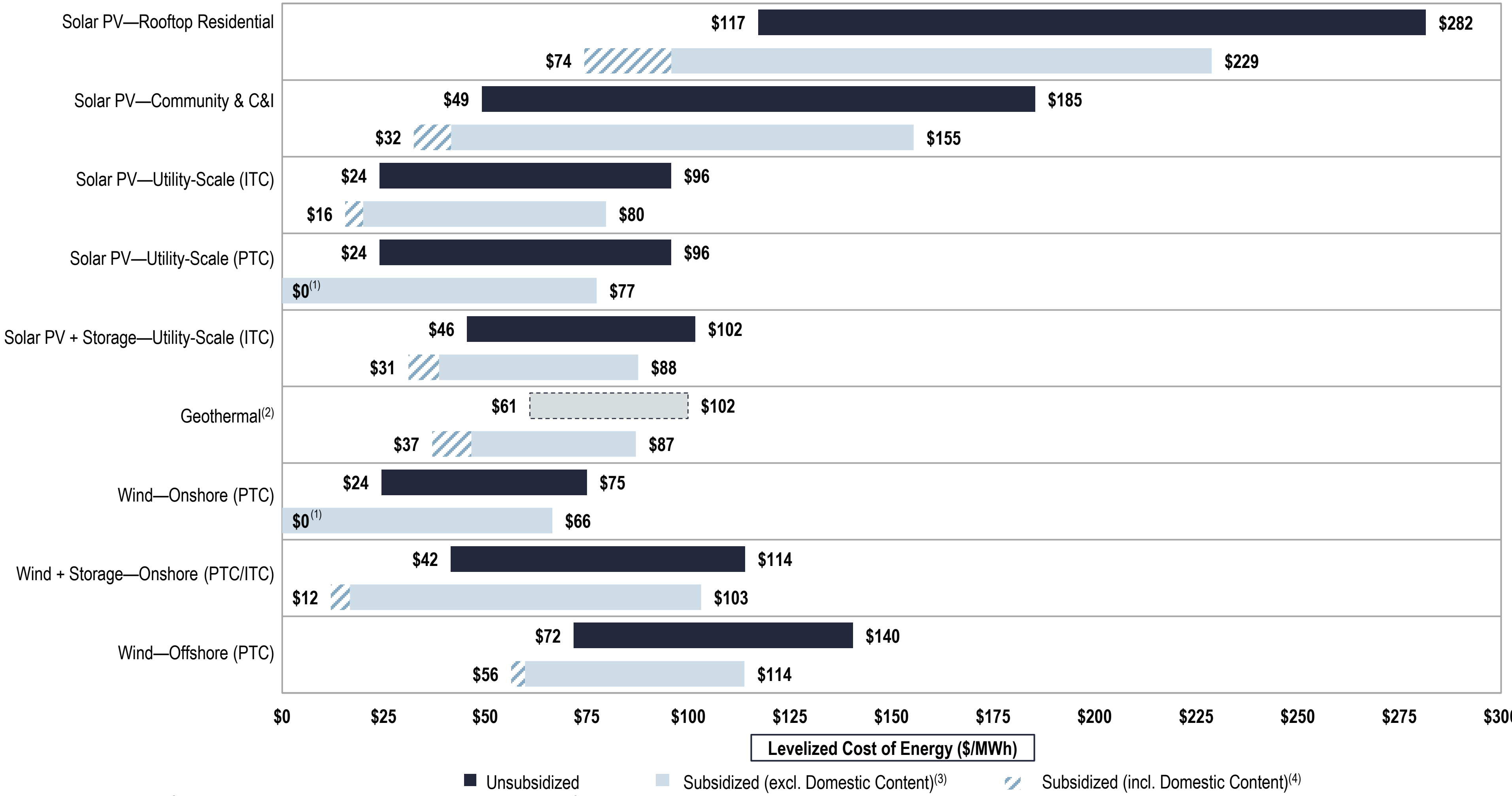
(5) Given the limited public and/or observable data set available for new-build coal projects, the LCOE presented herein represents Lazard's LCOE v15.0 results adjusted for inflation. High end incorporates 90% carbon capture and storage ("CCS"). Does not include cost of transportation and storage.

(6) Represents the LCOE of the observed high case gas combined cycle inputs using a 20% blend of "Blue" hydrogen, (i.e., hydrogen produced from a steam-methane reformer, using natural gas as a feedstock, and sequestering the resulting CO_2 in a nearby saline aquifer). No plant modifications are assumed beyond a 2% adjustment to the plant's heat rate. The corresponding fuel cost is $5.20/MMBTU, assuming ~$1.40/kg for Blue hydrogen.

(7) Represents the LCOE of the observed high case gas combined cycle inputs using a 20% blend of "Green" hydrogen, (i.e., hydrogen produced from an electrolyzer powered by a mix of wind and solar generation and stored in a nearby salt cavern). No plant modifications are assumed beyond a 2% adjustment to the plant's heat rate. The corresponding fuel cost is $10.05/MMBTU, assuming ~$4.15/kg for Green hydrogen.

Levelized Cost of Energy Comparison—Sensitivity to U.S. Federal Tax Subsidies

The Investment Tax Credit ("ITC"), Production Tax Credit ("PTC") and domestic content adder, among other provisions in the IRA, are important components of the levelized cost of renewable energy generation technologies



Source: *Lazard and Roland Berger estimates and publicly available information.*

Note: Unless otherwise indicated, this analysis does not include other state or federal subsidies (e.g., energy community adder, etc.). The IRA is comprehensive legislation that is still being implemented and remains subject to interpretation—important elements of the IRA are not included in our analysis and could impact outcomes.

(1) Results at this level are driven by Lazard's approach to calculating the LCOE and selected inputs (see Appendix for further details). Lazard's Unsubsidized LCOE analysis assumes, for year-over-year reference purposes, 60% debt at an 8% interest rate and 40% equity at a 12% cost (together implying an after-tax IRR/WACC of 7.7%). Implied IRRs at this level for Solar PV—Utility-Scale (PTC) equals 17% (excl. Domestic Content) and 22% (incl. Domestic Content) and implied IRRs at this level for Wind—Onshore (PTC) equals 17% (excl. Domestic Content) and 25% (incl. Domestic Content).

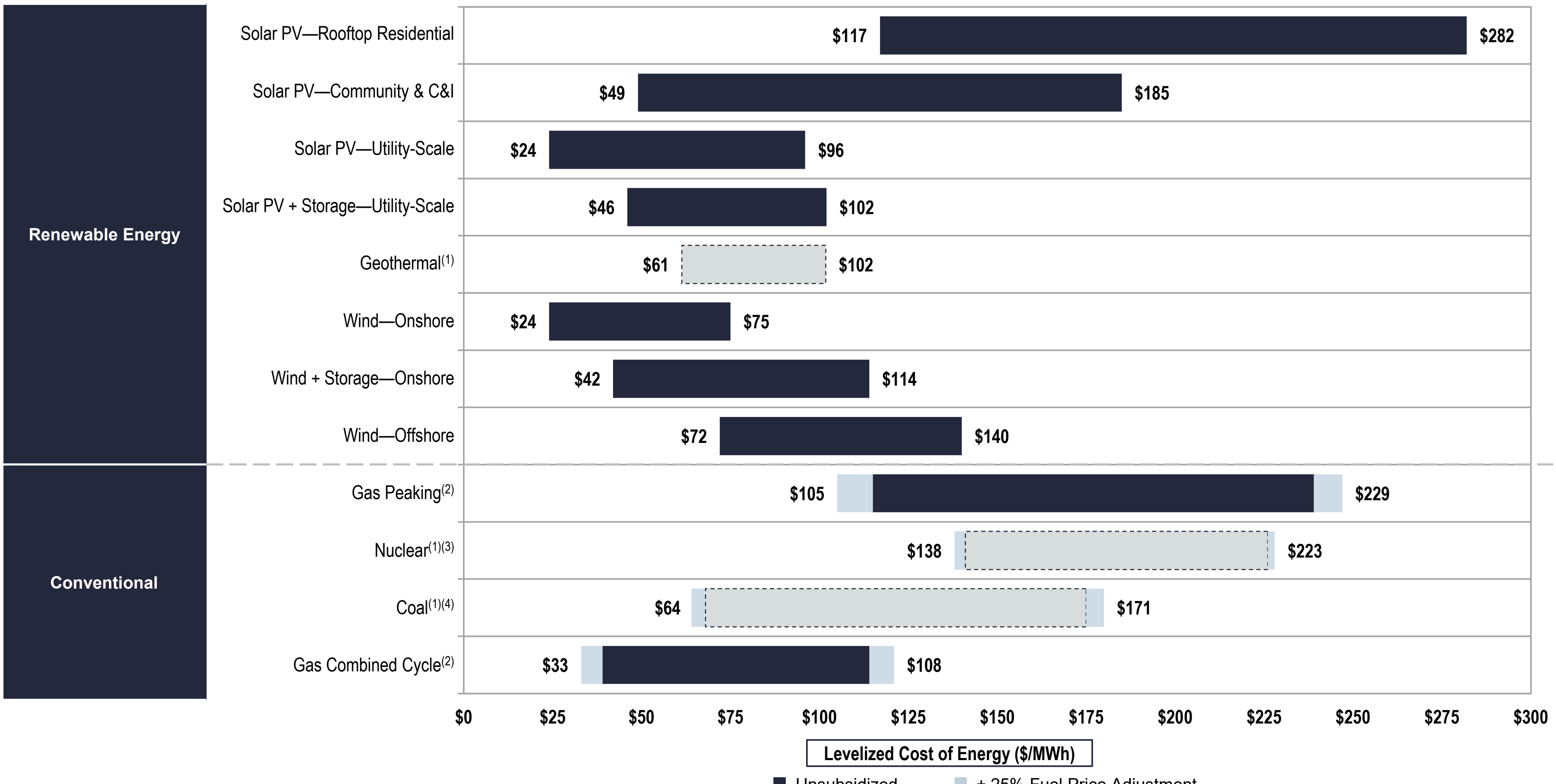
(2) Given the limited public and/or observable data set available for new-build geothermal projects, the LCOE presented herein represents Lazard's LCOE v15.0 results adjustment for inflation.

(3) This sensitivity analysis assumes that projects qualify for the full ITC/PTC and have a capital structure that includes sponsor equity, debt and tax equity.

(4) This sensitivity analysis assumes the above and also includes a 10% domestic content adder.

Levelized Cost of Energy Comparison—Sensitivity to Fuel Prices

Variations in fuel prices can materially affect the LCOE of conventional generation technologies, but direct comparisons to "competing" renewable energy generation technologies must take into account issues such as dispatch characteristics (e.g., baseload and/or dispatchable intermediate capacity vs. peaking or intermittent technologies)



Source: *Lazard and Roland Berger estimates and publicly available information.*

Note: Unless otherwise noted, the assumptions used in this sensitivity correspond to those used in the unsubsidized analysis as presented on the page titled "Levelized Cost of Energy Comparison—Unsubsidized Analysis".

(1) Given the limited public and/or observable data set available for new-build geothermal, coal and nuclear projects, and the emerging range of new nuclear generation strategies, the LCOE presented herein represents Lazard's LCOE v15.0 results adjusted for inflation and, for nuclear, are based on then-estimated costs of the Vogtle Plant and are U.S.-focused.

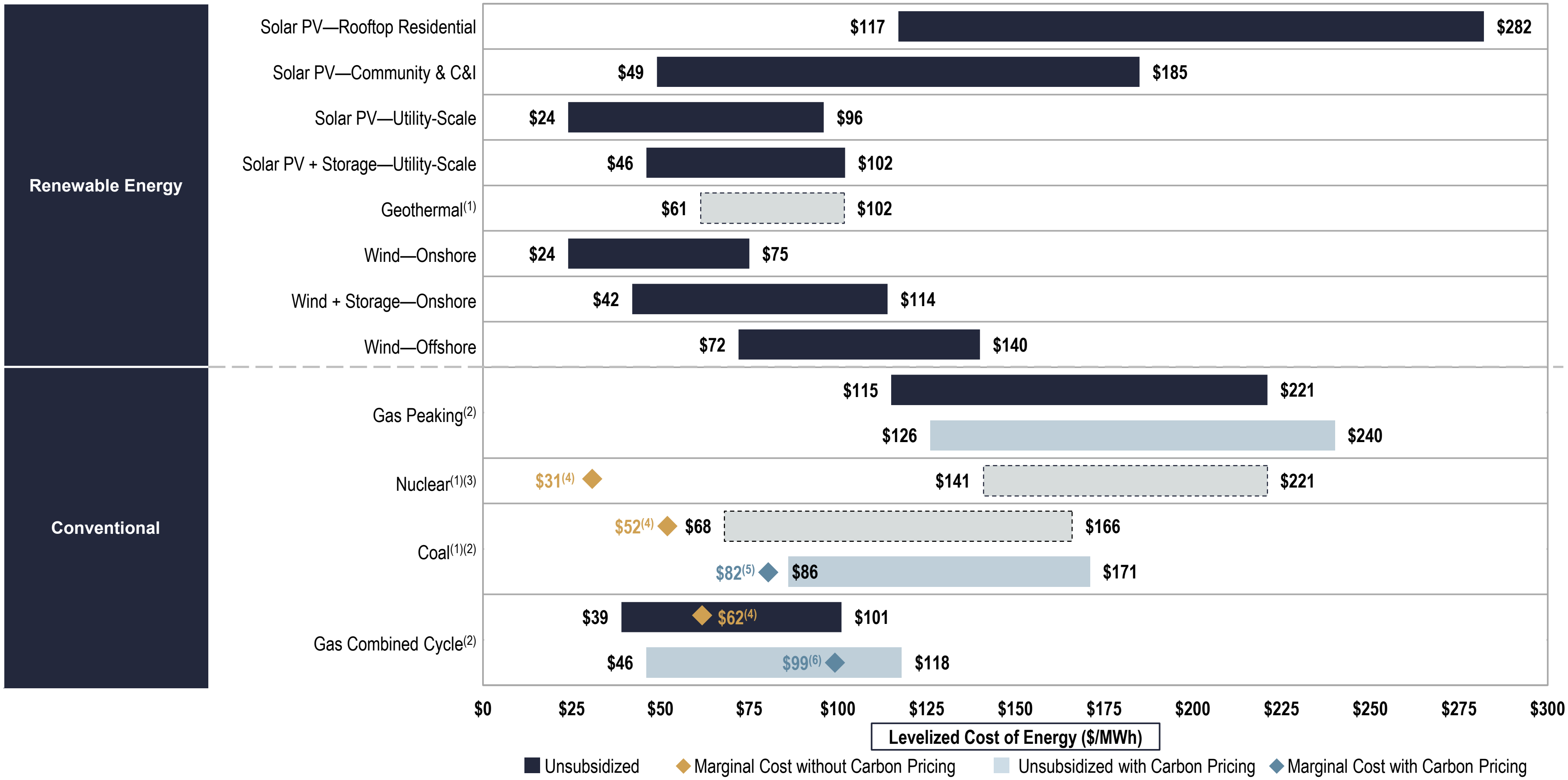
(2) Assumes a fuel cost range for gas-fired generation resources of $2.59/MMBTU – $4.31/MMBTU (representing a sensitivity range of ± 25% of the $3.45/MMBTU used in the Unsubsidized Analysis).

(3) Assumes a fuel cost range for nuclear generation resources of $0.64/MMBTU – $1.06/MMBTU (representing a sensitivity range of ± 25% of the $0.85MMBTU used in the Unsubsidized Analysis).

(4) Assumes a fuel cost range for coal-fired generation resources of $1.10/MMBTU – $1.84/MMBTU (representing a sensitivity range of ± 25% of the $1.47/MMBTU used in the Unsubsidized Analysis).

Levelized Cost of Energy Comparison—Sensitivity to Carbon Pricing

Carbon pricing is one avenue for policymakers to address carbon emissions; a carbon price range of \$20 – \$40/Ton of carbon would increase the LCOE for certain conventional generation technologies relative to those of onshore wind and utility-scale solar



Source: Lazard and Roland Berger estimates and publicly available information.

Note: Unless otherwise noted, the assumptions used in this sensitivity correspond to those used in the unsubsidized analysis as presented on the page titled "Levelized Cost of Energy Comparison—Unsubsidized Analysis".

(1) Given the limited public and/or observable data set available for new-build geothermal, coal and nuclear projects, and the emerging range of new nuclear generation strategies, the LCOE presented herein represents Lazard's LCOE v15.0 results adjusted for inflation and, for nuclear, are based on then-estimated costs of the Vogtle Plant and are U.S.-focused.

(2) The low and high ranges reflect the LCOE of selected conventional generation technologies including illustrative carbon prices of \$20/Ton and \$40/Ton, respectively.

(3) The IRA is comprehensive legislation that is still being implemented and remains subject to interpretation—important elements of the IRA (e.g., nuclear subsidies) are not included in our analysis and could impact outcomes.

(4) Represents the midpoint of the unsubsidized marginal cost of operating fully depreciated gas combined cycle, coal and nuclear facilities, inclusive of decommissioning costs for nuclear facilities. Analysis assumes that the salvage value for a decommissioned gas combined cycle or coal asset is equivalent to its decommissioning and site restoration costs. Inputs are derived from a benchmark of operating gas combined cycle, coal and nuclear assets across the U.S. Capacity factors, fuel, variable and fixed operating expenses are based on upper- and lower-quartile estimates derived from Lazard's research. See page titled "Levelized Cost of Energy Comparison—Renewable Energy versus Marginal Cost of Selected Existing Conventional Generation Technologies" for additional details.

(5) Represents the midpoint of the unsubsidized marginal cost of operating fully depreciated coal facilities with illustrative carbon pricing. Operating coal facilities are not assumed to employ CCS technology.

(6) Represents the midpoint of the unsubsidized marginal cost of operating fully depreciated gas combined cycle facilities with illustrative carbon pricing.

Levelized Cost of Energy Comparison—Sensitivity to Cost of Capital

A key consideration in determining the LCOE values for utility-scale generation technologies is the cost, and availability, of capital[1]; this dynamic is particularly significant for renewable energy generation technologies

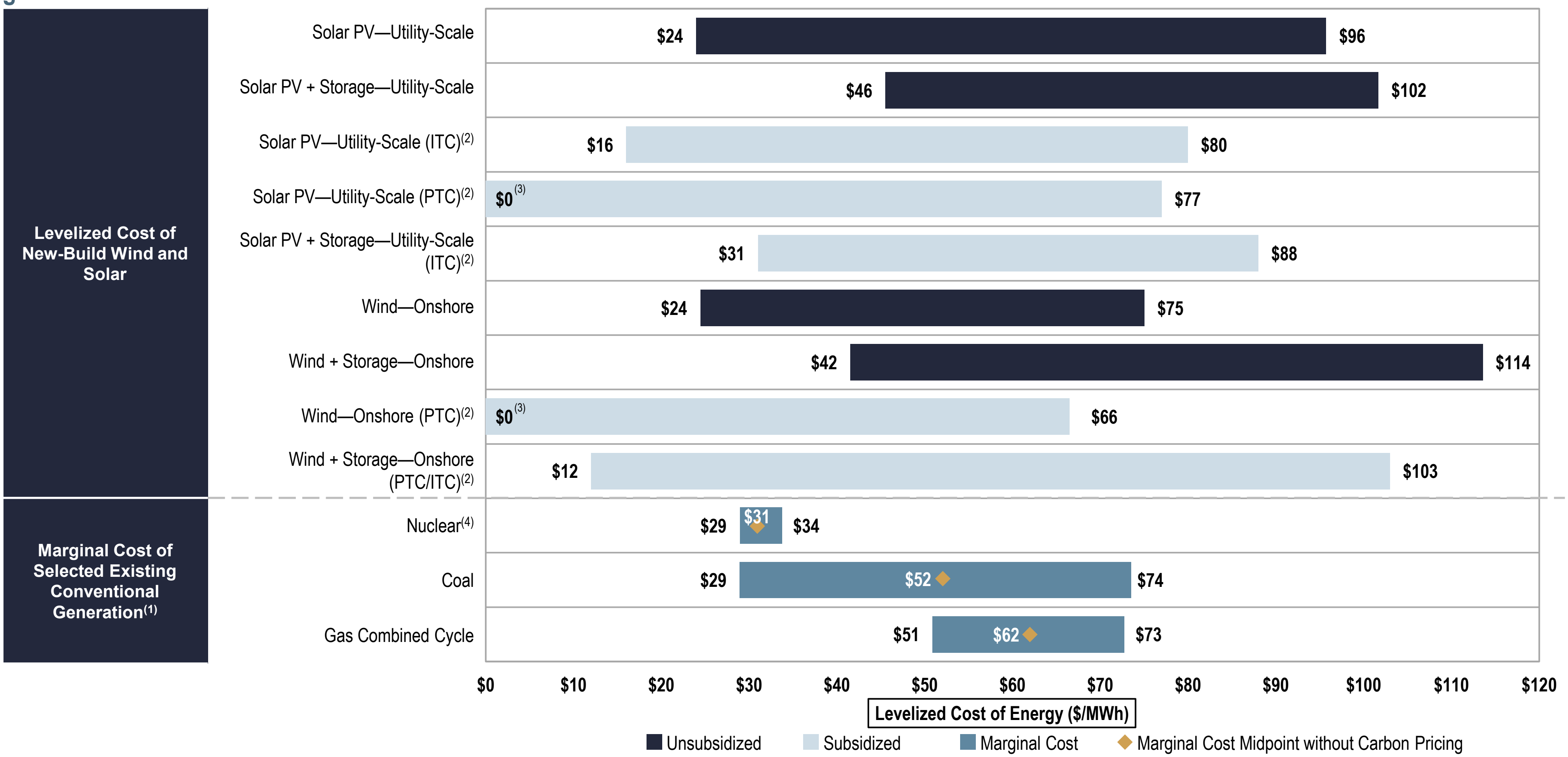
Midpoint of Unsubsidized LCOE[2]

After-Tax IRR/WACC	4.2%	5.4%	6.5%	7.7%	8.8%	10.0%
Cost of Equity	6.0%	8.0%	10.0%	12.0%	14.0%	16.0%
Cost of Debt	5.0%	6.0%	7.0%	8.0%	9.0%	10.0%

Source: *Lazard and Roland Berger estimates and publicly available information.*
Note: Analysis assumes 60% debt and 40% equity. Unless otherwise noted, the assumptions used in this sensitivity correspond to those used on the page titled "Levelized Cost of Energy Comparison—Unsubsidized Analysis".
(1) Cost of capital as used herein indicates the cost of capital applicable to the asset/plant and not the cost of capital of a particular investor/owner.
(2) Reflects the average of the high and low LCOE for each respective cost of capital assumption.

Levelized Cost of Energy Comparison—Renewable Energy versus Marginal Cost of Selected Existing Conventional Generation Technologies

Certain renewable energy generation technologies have an LCOE that is competitive with the marginal cost of existing conventional generation



Source: *Lazard and Roland Berger estimates and publicly available information.*

Note: Unless otherwise noted, the assumptions used in this sensitivity correspond to those used on page titled "Levelized Cost of Energy Comparison—Unsubsidized Analysis".

(1) Represents the marginal cost of operating fully depreciated gas combined cycle, coal and nuclear facilities, inclusive of decommissioning costs for nuclear facilities. Analysis assumes that the salvage value for a decommissioned gas combined cycle and coal asset is equivalent to its decommissioning and site restoration costs. Inputs are derived from a benchmark of operating gas combined cycle, coal and nuclear assets across the U.S. Capacity factors, fuel, variable and fixed O&M are based on upper- and lower-quartile estimates derived from Lazard's research. Assumes a fuel cost of $0.79/MMBTU for Nuclear, $3.11/MMBTU for Coal and $6.85/MMBTU for Gas Combined Cycle.

(2) See page titled "Levelized Cost of Energy Comparison—Sensitivity to U.S. Federal Tax Subsidies" for additional details.

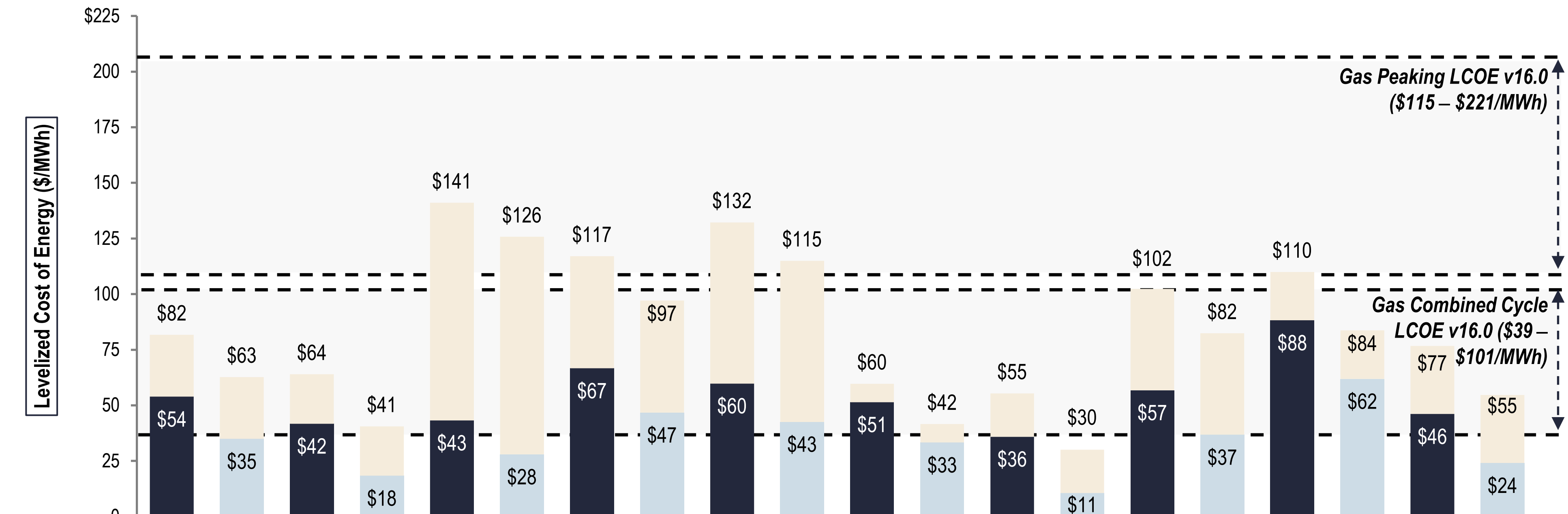
(3) Results at this level are driven by Lazard's approach to calculating the LCOE and selected inputs (see Appendix for further details). Lazard's Unsubsidized LCOE analysis assumes, for year-over-year reference purposes, 60% debt at an 8% interest rate and 40% equity at a 12% cost (together implying an after-tax IRR/WACC of 7.7%). Implied IRRs at this level for Solar PV—Utility-Scale (PTC) equals 17% (excl. Domestic Content) and 22% (incl. Domestic Content) and implied IRRs at this level for Wind—Onshore (PTC) equals 17% (excl. Domestic Content) and 25% (incl. Domestic Content).

(4) The IRA is comprehensive legislation that is still being implemented and remains subject to interpretation—important elements of the IRA (e.g., nuclear subsidies) are not included in our analysis and could impact outcomes.

Levelized Cost of Energy Comparison—Cost of Firming Intermittency

The incremental cost to firm[(1)] intermittent resources varies regionally, depending on the current effective load carrying capability ("ELCC")[(2)] values and the current cost of adding new firming resources—carbon pricing, not considered below, would have an impact on this analysis

LCOE v16.0 Levelized Firming Cost ($/MWh)[(3)]



	Solar	Wind	Solar	PV + Storage	Wind	Solar	Wind	Solar	PV + Storage	Wind
ELCC	50%	16%	7%	51%[(4)]	15%	85%	17%	38%	70%[(4)]	15%
Capacity Factor	20%	43%	25%	25%	30%	21%	50%	19%	19%	39%
Resource Penetration	3%	25%	32%	32%	19%	1%	56%	5%	5%	7%
	MISO		CAISO			SPP		PJM		

■ Lazard's Unsubsidized LCOE[(3)] ■ Lazard's Subsidized LCOE[(3)] ■ Firming Cost[(1)]

Source: Lazard and Roland Berger estimates and publicly available information.

(1) Firming costs reflect the additional capacity needed to supplement the net capacity of the renewable resource (nameplate capacity * (1 – ELCC)) and the net cost of new entry (net "CONE") of a new firm resource (capital and operating costs, less expected market revenues). Net CONE is assessed and published by grid operators for each regional market. Grid operators use a natural gas CT as the assumed new resource in MISO ($8.22/kW-mo), SPP ($8.56/kW-mo) and PJM ($10.20/kW-mo). In CAISO, the assumed new resource is a 4 hour lithium-ion battery storage system ($18.92/kW-mo). For the PV + Storage cases in CAISO and PJM, assumed Storage configuration is 50% of PV MW and 4 hour duration.

(2) ELCC is an indicator of the reliability contribution of different resources to the electricity grid. The ELCC of a generation resource is based on its contribution to meeting peak electricity demand. For example, a 1 MW wind resource with a 15% ELCC provides 0.15 MW of capacity contribution and would need to be supplemented with 0.85 MW of additional firm capacity in order to represent the addition of 1 MW of firm system capacity.

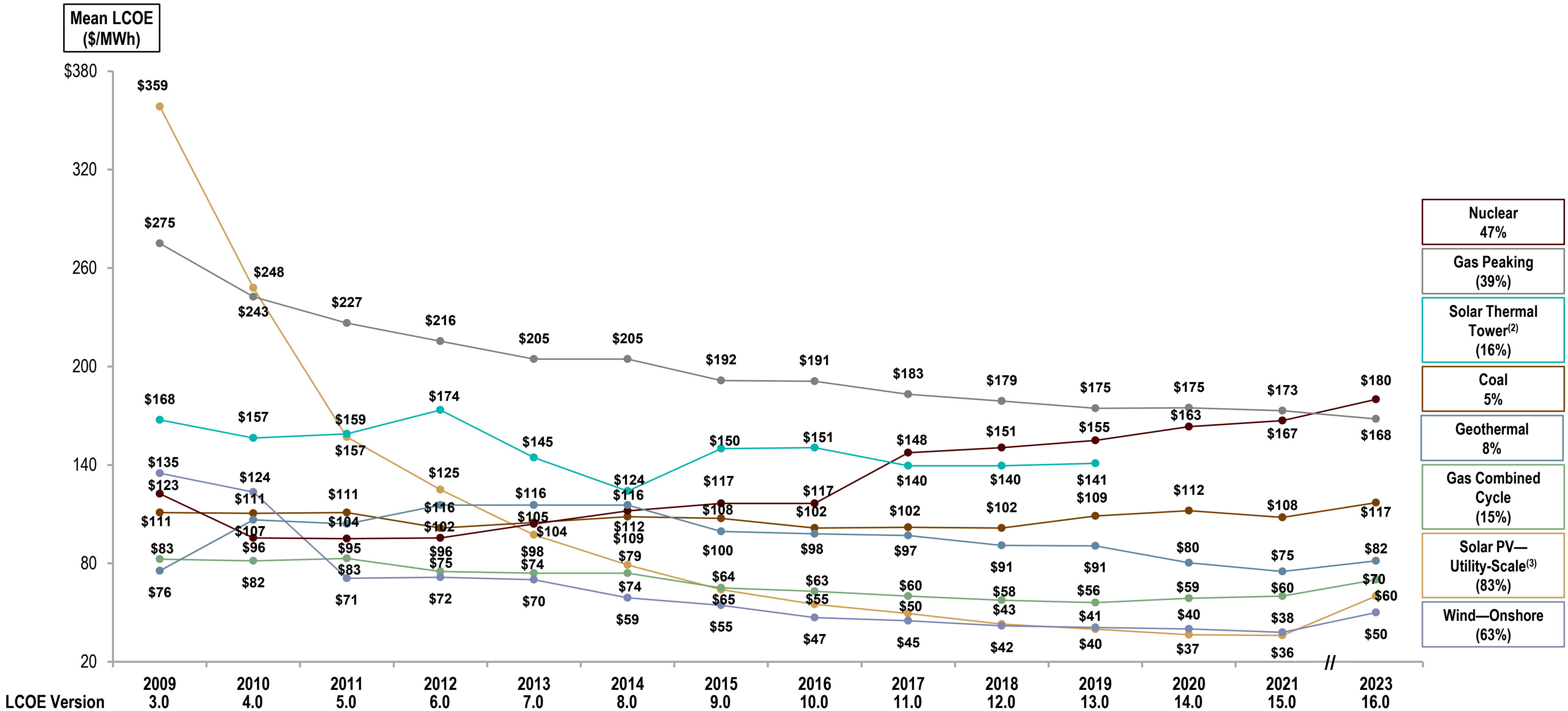
(3) LCOE values represent the midpoint of Lazard's LCOE v16.0 cost inputs for each technology adjusted for a regional capacity factor to demonstrate the regional differences in both project and firming costs.

(4) For PV + Storage cases, the effective ELCC value is represented. CAISO and PJM assess ELCC values separately for the PV and storage components of a system. Storage ELCC value is provided only for the capacity that can be charged directly by the accompanying resource up to the energy required for a 4 hour discharge during peak load. Any capacity available in excess of the 4 hour maximum discharge is attributed to the system at the solar ELCC. ELCC values for storage range from 90% – 95% for CAISO and PJM.

Levelized Cost of Energy Comparison—Historical Utility-Scale Generation Comparison

Lazard's unsubsidized LCOE analysis indicates significant historical cost declines for utility-scale renewable energy generation technologies driven by, among other factors, decreasing capital costs, improving technologies and increased competition

Selected Historical Mean Unsubsidized LCOE Values(1)



Source: *Lazard and Roland Berger estimates and publicly available information.*

(1) Reflects the average of the high and low LCOE for each respective technology in each respective year. Percentages represent the total decrease in the average LCOE since Lazard's LCOE v3.0.

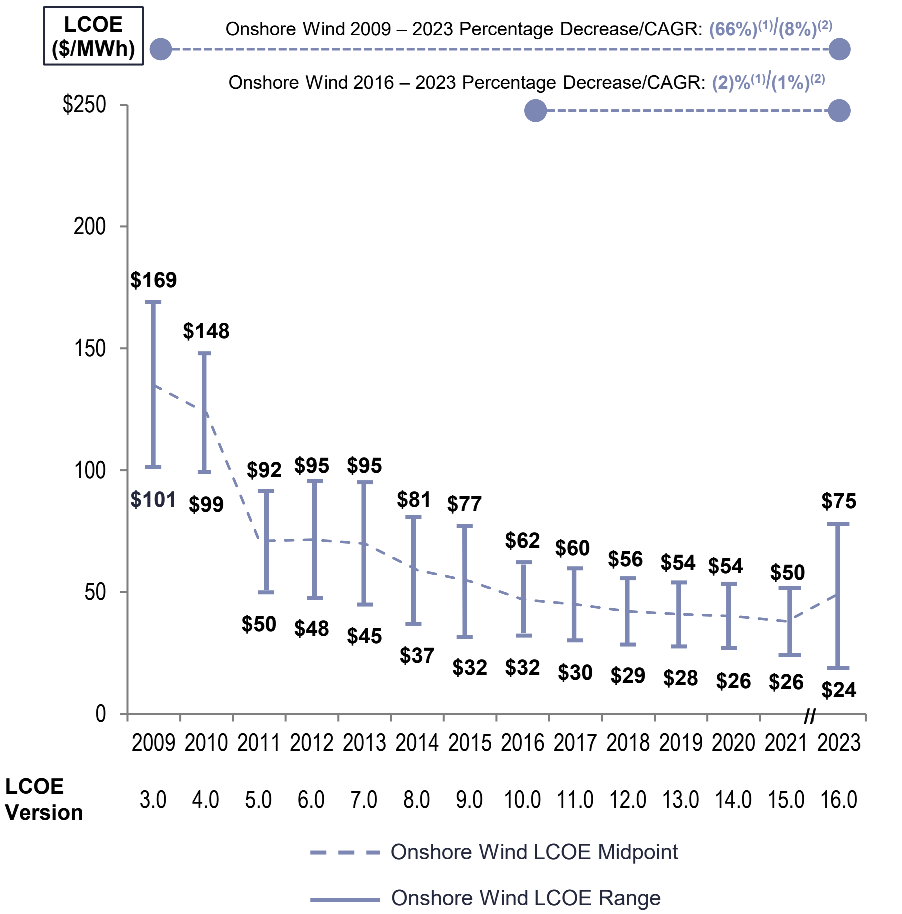
(2) The LCOE no longer analyzes solar thermal costs; percent decrease is as of Lazard's LCOE v13.0.

(3) Prior versions of Lazard's LCOE divided Utility-Scale Solar PV into Thin Film and Crystalline subcategories. All values before Lazard's LCOE v16.0 reflect those of the Solar PV—Crystalline technology.

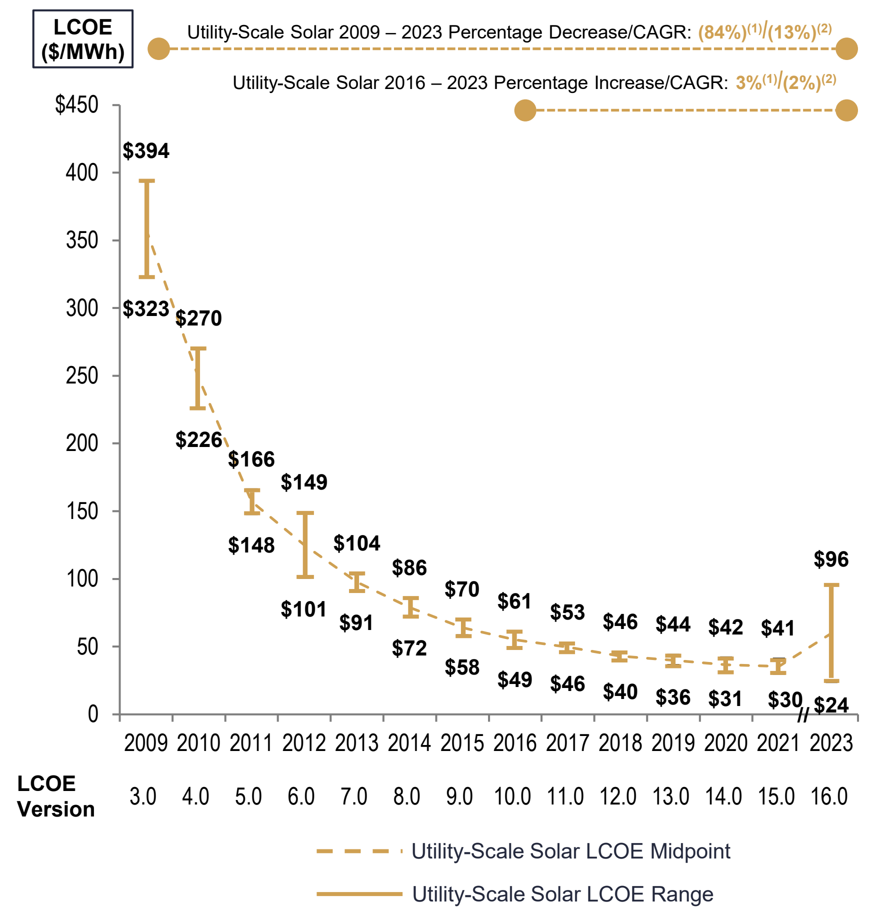
Levelized Cost of Energy Comparison—Historical Renewable Energy LCOE

Even in the face of inflation and supply chain challenges, the LCOE of best-in-class onshore wind and utility-scale solar has declined at the low-end of our cost range, the reasons for which could catalyze ongoing consolidation across the sector—although the average LCOE has increased for the first time in the history of our studies

Unsubsidized Onshore Wind LCOE



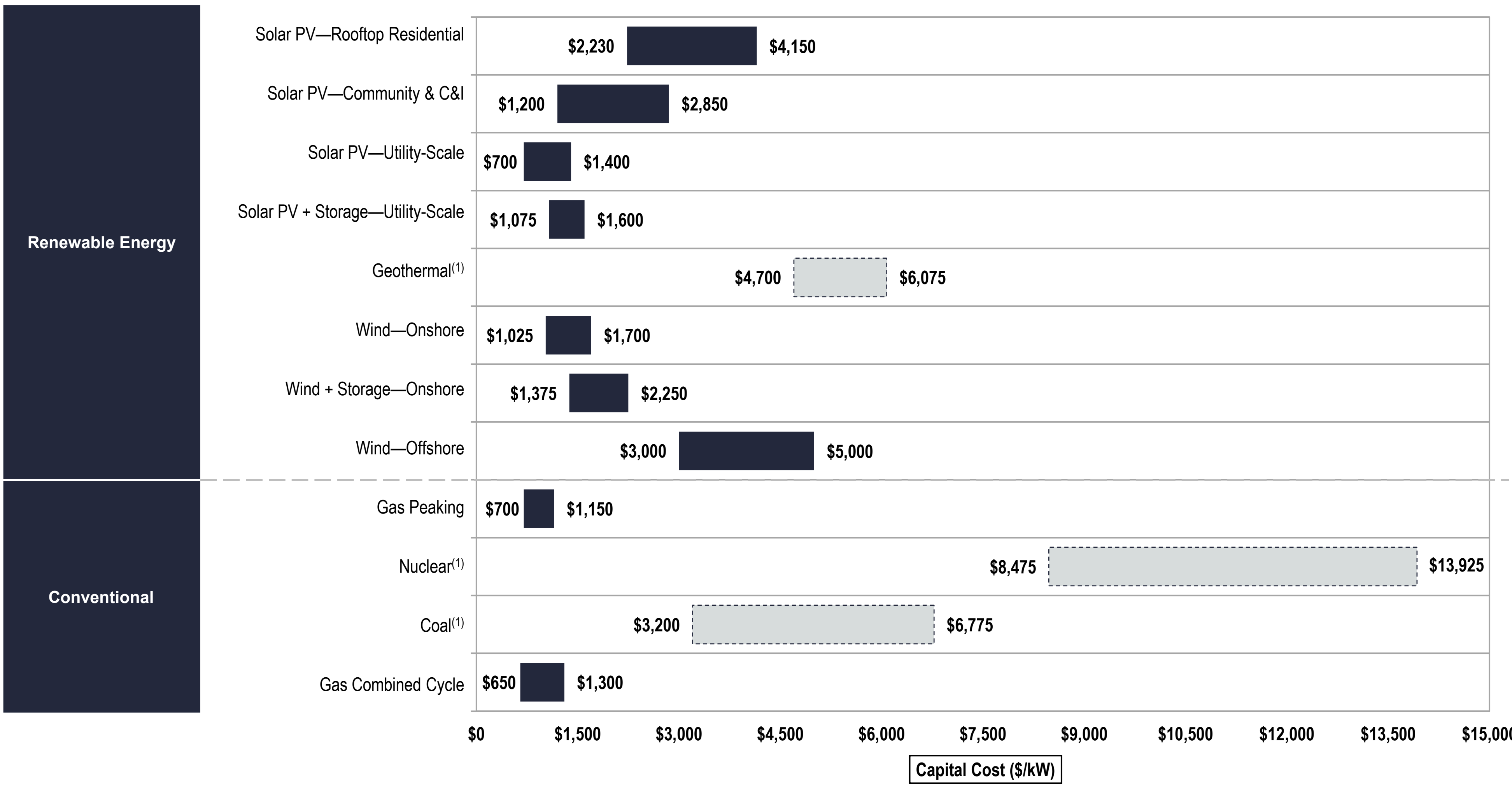
Unsubsidized Solar PV LCOE



Source: Lazard and Roland Berger estimates and publicly available information.
(1) Represents the average percentage decrease/increase of the high end and low end of the LCOE range.
(2) Represents the average compounded annual rate of decline of the high end and low end of the LCOE range.

Levelized Cost of Energy Comparison—Capital Cost Comparison

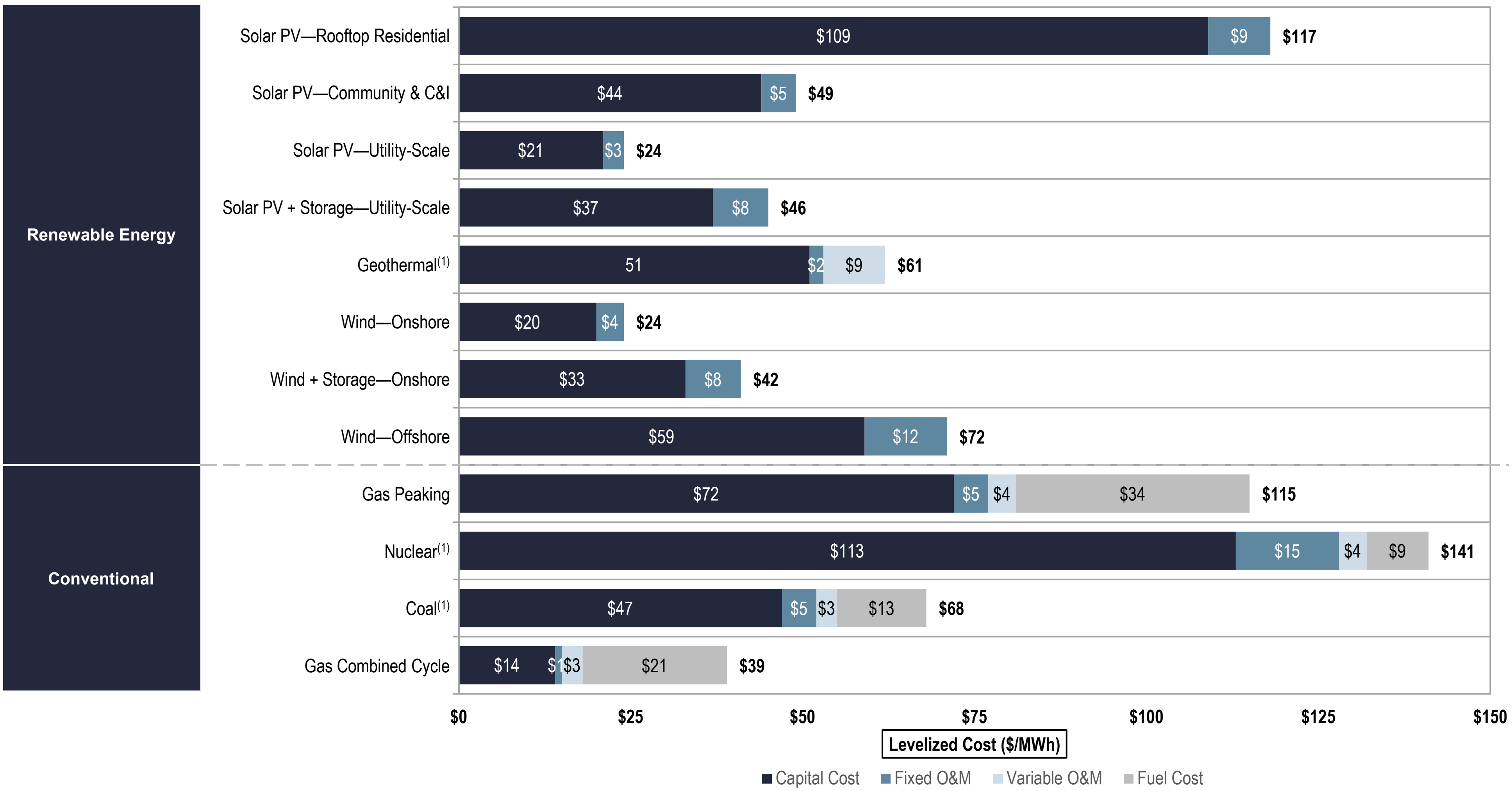
In some instances, the capital costs of renewable energy generation technologies have converged with those of certain conventional generation technologies, which coupled with improvements in operational efficiency for renewable energy technologies, have led to a convergence in LCOE between the respective technologies



Source: *Lazard and Roland Berger estimates and publicly available information.*
Notes: Figures may not sum due to rounding.
(1) Given the limited public and/or observable data set available for new-build geothermal, coal and nuclear projects, and the emerging range of new nuclear generation strategies, the LCOE presented herein represents Lazard's LCOE v15.0 results adjusted for inflation and, for nuclear, are based on then-estimated costs of the Vogtle Plant and are U.S.-focused.

Levelized Cost of Energy Components—Low End

Certain renewable energy generation technologies are already cost-competitive with conventional generation technologies; key factors regarding the continued cost decline of renewable energy generation technologies are the ability of technological development and industry scale to continue lowering operating expenses and capital costs for renewable energy generation technologies



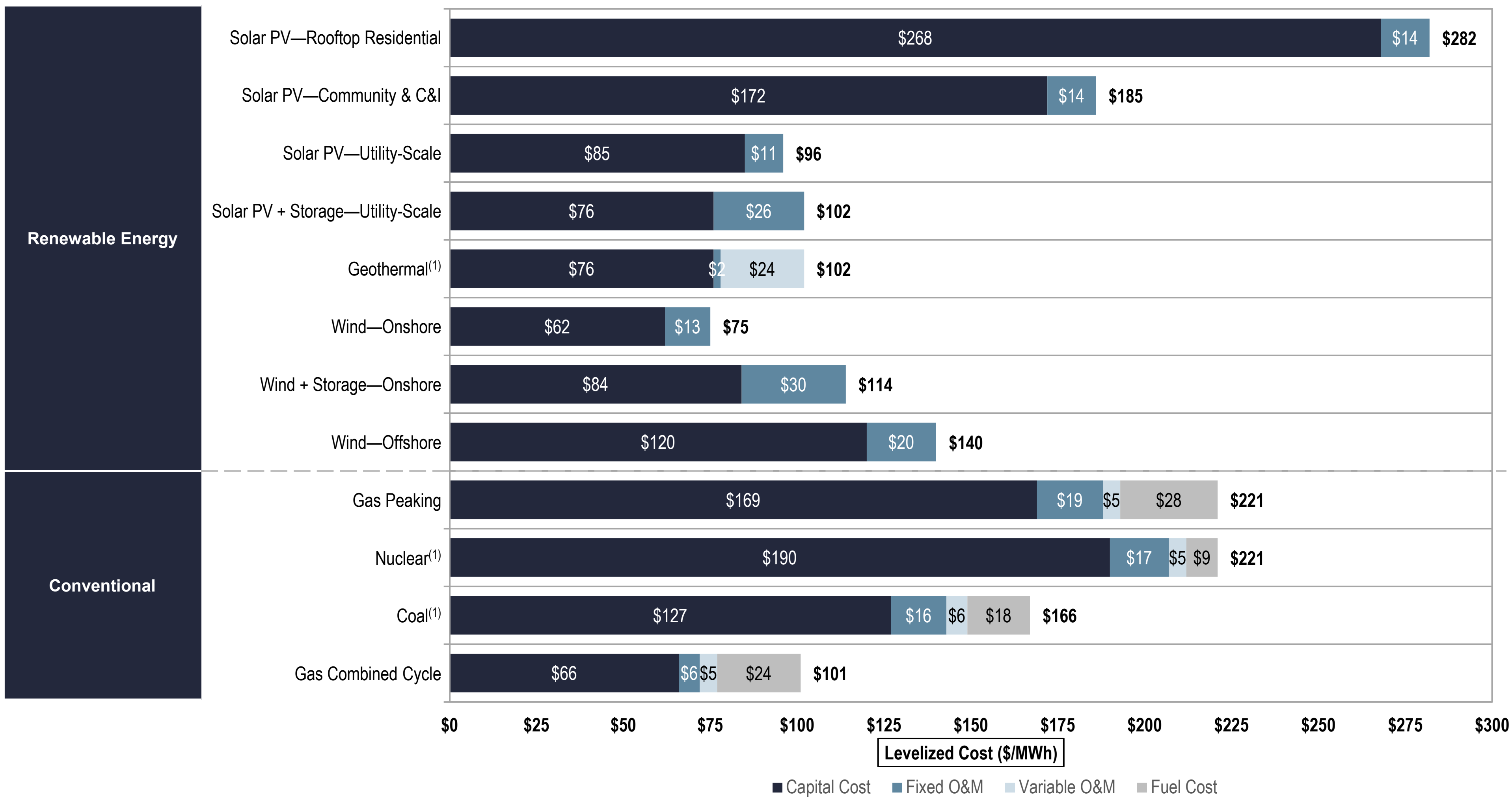
Source: Lazard and Roland Berger estimates and publicly available information.

Notes: Figures may not sum due to rounding.

(1) Given the limited public and/or observable data set available for new-build geothermal, coal and nuclear projects, and the emerging range of new nuclear generation strategies, the LCOE presented herein represents Lazard's LCOE v15.0 results adjusted for inflation and, for nuclear, are based on then-estimated costs of the Vogtle Plant and are U.S.-focused.

Levelized Cost of Energy Components—High End

Certain renewable energy generation technologies are already cost-competitive with conventional generation technologies; key factors regarding the continued cost decline of renewable energy generation technologies are the ability of technological development and industry scale to continue lowering operating expenses and capital costs for renewable energy generation technologies



Source: *Lazard and Roland Berger estimates and publicly available information.*

Notes: Figures may not sum due to rounding.

(1) Given the limited public and/or observable data set available for new-build geothermal, coal and nuclear projects, and the emerging range of new nuclear generation strategies, the LCOE presented herein represents Lazard's LCOE v15.0 results adjusted for inflation and, for nuclear, are based on then-estimated costs of the Vogtle Plant and are U.S.-focused.

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Energy Resources—Matrix of Applications

Despite convergence in the LCOE of certain renewable energy and conventional generation technologies, direct comparisons must take into account issues such as location (e.g., centralized vs. distributed) and dispatch characteristics (e.g., baseload and/or dispatchable intermediate capacity vs. peaking or intermittent technologies)

		Carbon Neutral/ REC Potential	Location			Dispatch			
			Distributed	Centralized	Geography	Intermittent	Peaking	Load-Following	Baseload
Renewable Energy	Solar PV[1]	✓	✓	✓	Universal	✓	✓		
	Solar PV + Storage	✓	✓	✓	Universal	✓	✓		
	Geothermal	✓		✓	Varies				✓
	Onshore Wind	✓		✓	Rural	✓			
	Onshore Wind + Storage	✓		✓	Rural	✓	✓		
	Offshore Wind	✓		✓	Coastal	✓			
Conventional	Gas Peaking	✗	✓	✓	Universal		✓	✓	
	Nuclear	✓		✓	Rural				✓
	Coal	✗		✓	Co-located or rural				✓
	Gas Combined Cycle	✗		✓	Universal			✓	✓

Source: Lazard and Roland Berger estimates and publicly available information.
(1) Represents the full range of solar PV technologies.

II Lazard's Levelized Cost of Storage Analysis—Version 8.0

Introduction

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

- **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 basis
  - Comparative LCOS analysis for various energy storage systems on a $/MWh basis
- **Energy Storage Value Snapshot analysis**
  - Overview of potential revenue applications for various energy storage systems
  - Overview of the Value Snapshot analysis and identification of selected geographies for each use case analyzed
  - Summary results from the Value Snapshot analysis
- **Appendix materials, including:**
  - An overview of the methodology utilized to prepare Lazard's LCOS analysis
  - A summary of the assumptions utilized in Lazard's LCOS analysis

Other factors would also have a potentially significant effect on the results contained herein, but have not been examined in the scope of this current analysis. These additional factors, among others, could include: implementation and interpretation of the full scope of the IRA; network upgrades, transmission, congestion or other integration-related costs; permitting or other development costs, unless otherwise noted; and costs of complying with various regulations (e.g., federal import tariffs or labor requirements). This analysis also does not address potential social and environmental externalities, as well as the long-term residual and societal consequences of various energy storage system technologies that are difficult to measure (e.g., resource extraction, end of life disposal, lithium-ion-related safety hazards, etc.)

Note: This report has been compiled using U.S.-focused data.

Energy Storage Use Cases—Overview

By identifying and evaluating selected energy storage applications, Lazard's LCOS analyzes the cost of energy storage for in-front-of-the-meter and behind-the-meter use cases

		Use Case Description	Technologies Assessed
In-Front-of-the-Meter	1 Utility-Scale (Standalone)	• 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 (LFP) • Lithium Nickel Manganese Cobalt Oxide (NMC)
In-Front-of-the-Meter	2 Utility-Scale (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 curtailment and provide grid support	• Lithium Iron Phosphate (LFP) • Lithium Nickel Manganese Cobalt Oxide (NMC)
In-Front-of-the-Meter	3 Utility-Scale (Wind + Storage)	• Energy storage system designed to be paired with large wind generation facilities to better align timing of wind generation with system demand, reduce curtailment and provide grid support	• Lithium Iron Phosphate (LFP) • Lithium Nickel Manganese Cobalt Oxide (NMC)
Behind-the-Meter	4 Commercial & Industrial (Standalone)	• Energy storage system designed for behind-the-meter peak shaving and demand charge reduction for C&I 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 (LFP) • Lithium Nickel Manganese Cobalt Oxide (NMC)
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 users – Systems designed to maximize the value of the solar PV system by optimizing available revenue streams and subsidies	• Lithium Iron Phosphate (LFP) • Lithium Nickel Manganese Cobalt Oxide (NMC)
Behind-the-Meter	6 Residential (Standalone)	• Energy storage system designed for behind-the-meter residential home use—provides backup power and power quality improvements – Depending on geography, can arbitrage residential time-of-use (TOU) rates and/or participate in utility demand response programs	• Lithium Iron Phosphate (LFP) • Lithium Nickel Manganese Cobalt Oxide (NMC)
Behind-the-Meter	7 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 (LFP) • Lithium Nickel Manganese Cobalt Oxide (NMC)

Source: Lazard and Roland Berger estimates and publicly available information.

(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 4 hour utility-scale use case.

Energy Storage Use Cases—Illustrative Operational Parameters

Lazard's LCOS evaluates selected energy storage applications and use cases by identifying illustrative operational parameters[1]

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

[ ] = "Usable Energy"[2]

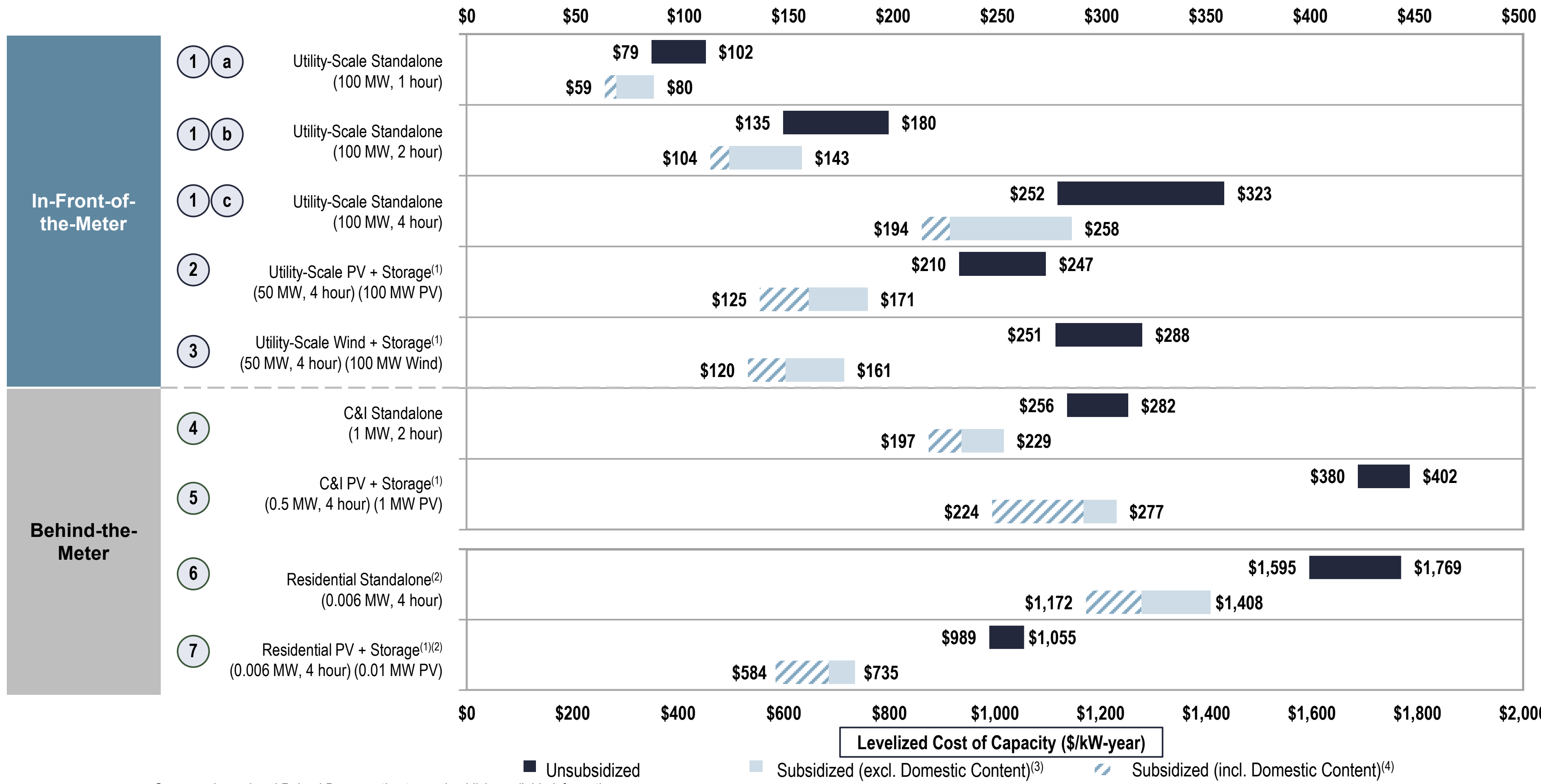
D = B x C; G = D x E x F; H = A x G

			A Project Life (Years)	B Storage (MW)[3]	Solar/ Wind (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[7]	H Project MWh
In-Front-of-the-Meter	1 Utility-Scale (Standalone)	a	20	100	–	2.6%	1	100	1	350	31,500	630,000
		b	20	100	–	2.6%	2	200	1	350	63,000	1,260,000
		c	20	100	–	2.6%	4	400	1	350	126,000	2,520,000
	2 Utility-Scale (PV + Storage)[8]		20	50	100	2.6%	4	200	1	350	191,000	3,820,000
	3 Utility-Scale (Wind + Storage)[8]		20	50	100	2.6%	4	200	1	350	366,000	7,320,000
Behind-the-Meter	4 Commercial & Industrial (Standalone)		20	1	–	2.6%	2	2	1	350	630	12,600
	5 Commercial & Industrial (PV + Storage)[8]		20	0.50	1	2.6%	4	2	1	350	1,690	33,800
	6 Residential (Standalone)		20	0.006	–	1.9%	4	0.025	1	350	8	158
	7 Residential (PV + Storage)[8]		20	0.006	0.010	1.9%	4	0.025	1	350	15	300

Source: *Lazard and Roland Berger estimates and publicly available information.*
Note: Operational parameters presented herein are applied to Value Snapshot and LCOS calculations. Annual and Project MWh in the Value Snapshot analysis may vary from the representative project.
(1) The use cases herein represent illustrative current and contemplated energy storage applications.
(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). A 90% DOD 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 as needed to ensure usable energy is maintained at the nameplate capacity, based on Year 1 storage module cost.
(8) For PV + Storage and Wind + Storage cases, annual MWh represents the net output of combined system (generator output, less storage "round trip efficiency" losses) assuming 100% storage charging from the generator.

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

Lazard's LCOS analysis evaluates standalone and hybrid energy storage systems on a levelized basis to derive cost metrics across energy storage use cases and configurations



Source: Lazard and Roland Berger estimates and publicly available information.

Note: Here and throughout this presentation, unless otherwise indicated, analysis assumes 20% debt at an 8% interest rate and 80% equity at a 12% cost, which is a different capital structure than Lazard's LCOE analysis and therefore numbers will not tie. Capital costs are comprised of the storage module, balance of system and power conversion equipment, collectively referred to as the energy storage system, equipment (where applicable) and EPC costs. Augmentation costs are included as part of O&M expenses in this analysis and vary across use cases due to usage profiles and lifespans. Charging costs for standalone cases are assessed at the weighted average hourly pricing (wholesale energy prices) across an optimized annual charging profile of the asset. No charging costs are assumed for hybrid systems. See Appendix for charging cost assumptions and additional details.

(1) For PV + Storage and Wind + Storage cases, the levelized cost is based on the capital and operating costs of the combined system, levelized over the net output of the combined system.

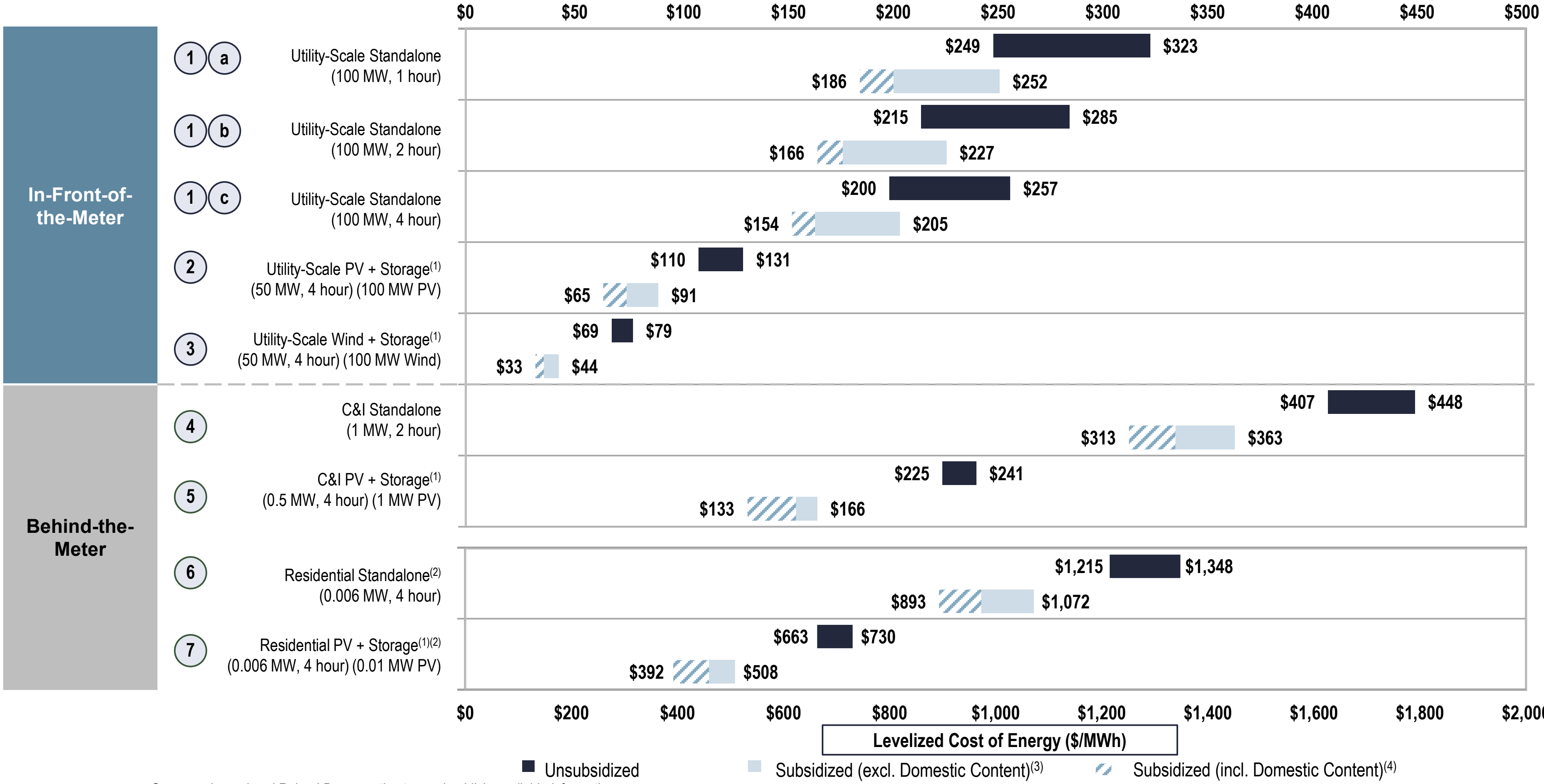
(2) In previous LCOS reports, residential battery storage costs have reflected equipment purchase costs only. For Lazard's LCOE v16.0 and LCOS v8.0, capital costs for residential battery storage projects includes installation/labor, balance-of-system components and warranties.

(3) This sensitivity analysis assumes that projects qualify for the full ITC/PTC and have a capital structure that includes sponsor equity, debt and tax equity. In this analysis only the wind portion of the Wind + Storage system utilizes the PTC.

(4) This sensitivity analysis assumes the above and also includes a 10% domestic content adder.

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

Lazard's LCOS analysis evaluates standalone and hybrid energy storage systems on a levelized basis to derive cost metrics across energy storage use cases and configurations



Source: *Lazard and Roland Berger estimates and publicly available information.*

Note: Here and throughout this presentation, unless otherwise indicated, analysis assumes 20% debt at an 8% interest rate and 80% equity at a 12% cost, which is a different capital structure than Lazard's LCOE analysis and therefore numbers will not tie. Capital costs are comprised of the storage module, balance of system and power conversion equipment, collectively referred to as the energy storage system, equipment (where applicable) and EPC costs. Augmentation costs are included as part of O&M expenses in this analysis and vary across use cases due to usage profiles and lifespans. Charging costs for standalone cases are assessed at the weighted average hourly pricing (wholesale energy prices) across an optimized annual charging profile of the asset. No charging costs are assumed for hybrid systems. See Appendix for charging cost assumptions and additional details.

(1) For PV + Storage and Wind + Storage cases, the levelized cost is based on the capital and operating costs of the combined system, levelized over the net output of the combined system.

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(4) This sensitivity analysis assumes the above and also includes a 10% domestic content adder.

Value Snapshots—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 clearly identifiable or without publicly available data have not been analyzed**

		Description	Use Cases[(1)]						
			Utility-Scale (S)	Utility-Scale (PV + S)	Utility-Scale (Wind + S)	Commercial & Industrial (S)	Commercial & Industrial (PV + S)	Residential (PV + S)	Residential standalone (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 load	✓	✓	✓				
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	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				✓	✓	✓	✓
Customer	Backup Power	• Provides backup power for use by Residential and Commercial customers during grid outages				✓	✓	✓	✓

Source: *Lazard and Roland Berger estimates, Enovation Analytics and publicly available information.*
(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

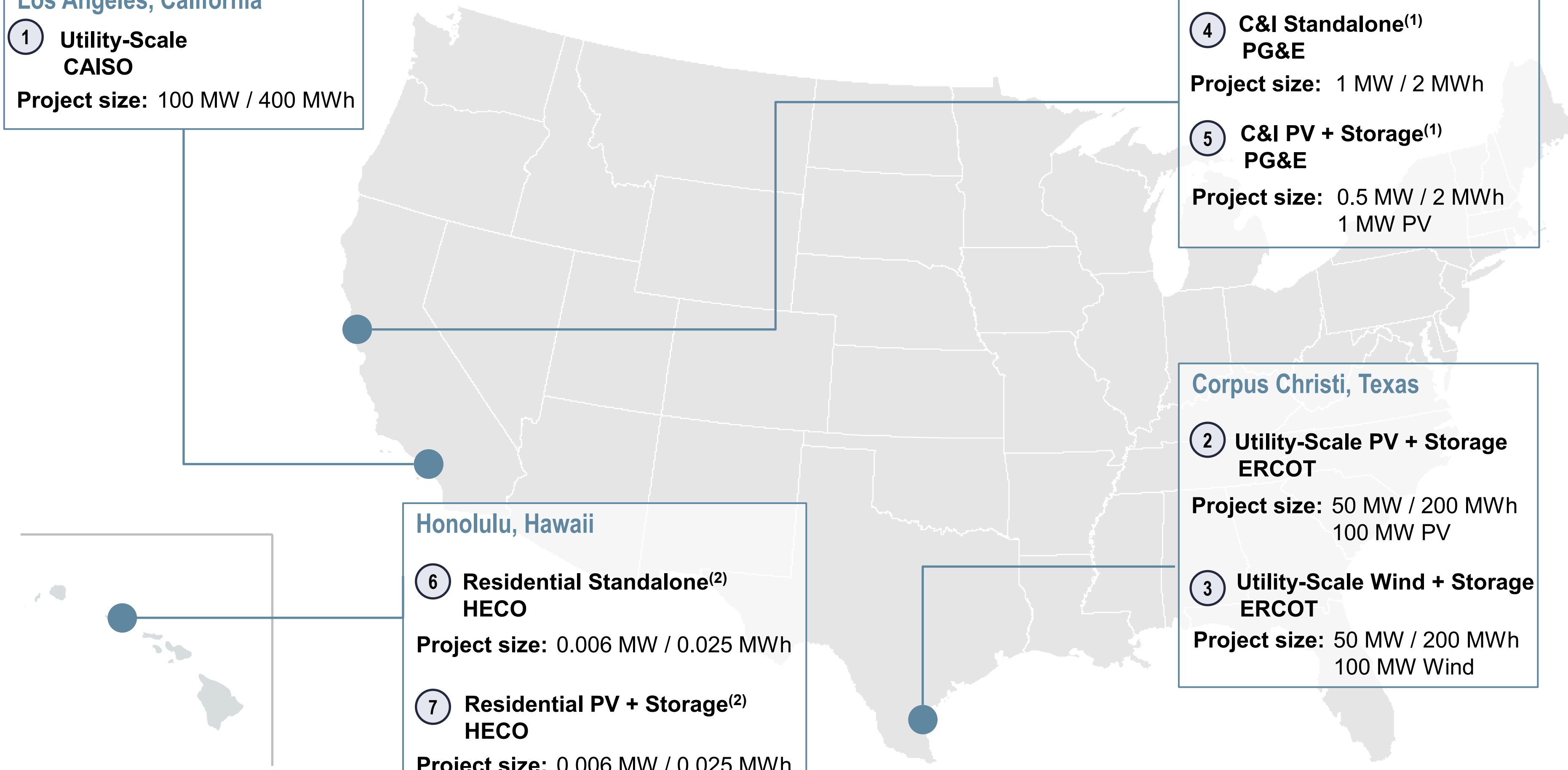
Lazard's Value Snapshots analyze the financial viability of illustrative energy storage systems designed for selected use cases

		Location	Description	Storage (MW)	Generation (MW)	Storage Duration (hours)	Revenue Streams
In-Front-of-the-Meter	1 Utility-Scale (Standalone)	CAISO[1] (SP-15)	Large-scale energy storage system	100	–	4	• Energy Arbitrage • Frequency Regulation • Resource Adequacy • Spinning/Non-spinning Reserves
	2 Utility-Scale (PV + Storage)	ERCOT[2] (South Texas)	Energy storage system designed to be paired with large solar PV facilities	50	100	4	
	3 Utility-Scale (Wind + Storage)	ERCOT[2] (South Texas)	Energy storage system designed to be paired with large wind generation facilities	50	100	4	
Behind-the-Meter	4 Commercial & Industrial (Standalone)	PG&E[3] (California)	Energy storage system designed for behind-the-meter peak shaving and demand charge reduction for C&I energy users	1	–	2	• Demand Response—Utility • Bill Management • Incentives • Tariff Settlement, DR Participation, Avoided Costs to Commercial Customer, Local Capacity Resource Programs and Incentives
	5 Commercial & Industrial (PV + Storage)	PG&E[3] (California)	Energy storage system designed for behind-the-meter peak shaving and demand charge reduction services for C&I energy users	0.5	1	4	
	6 Residential (Standalone)	HECO[4] (Hawaii)	Energy storage system designed for behind-the-meter residential home use—provides backup power and power quality improvements	0.006	–	4	• Demand Response—Utility • Bill Management/Tariff Settlement • Incentives
	7 Residential (PV + Storage)	HECO[4] (Hawaii)	Energy storage system designed for behind-the-meter residential home use—provides backup power, power quality improvements and extends usefulness of self-generation	0.006	0.01	4	

Source: Lazard and Roland Berger estimates, Enovation Analytics and publicly available information.
Note: Actual project returns may vary due to differences in location-specific costs, revenue streams and owner/developer risk preferences.
(1) Refers to the California Independent System Operator.
(2) Refers to the Electricity Reliability Council of Texas.
(3) Refers to Pacific Gas & Electric Company.
(4) Refers to Hawaiian Electric Company.

Value Snapshot Case Studies—Overview (cont'd)

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



Los Angeles, California

(1) **Utility-Scale**
CAISO

Project size: 100 MW / 400 MWh

San Francisco, California

(4) **C&I Standalone[1]**
PG&E

Project size: 1 MW / 2 MWh

(5) **C&I PV + Storage[1]**
PG&E

Project size: 0.5 MW / 2 MWh
1 MW PV

Honolulu, Hawaii

(6) **Residential Standalone[2]**
HECO

Project size: 0.006 MW / 0.025 MWh

(7) **Residential PV + Storage[2]**
HECO

Project size: 0.006 MW / 0.025 MWh
0.010 MW PV

Corpus Christi, Texas

(2) **Utility-Scale PV + Storage**
ERCOT

Project size: 50 MW / 200 MWh
100 MW PV

(3) **Utility-Scale Wind + Storage**
ERCOT

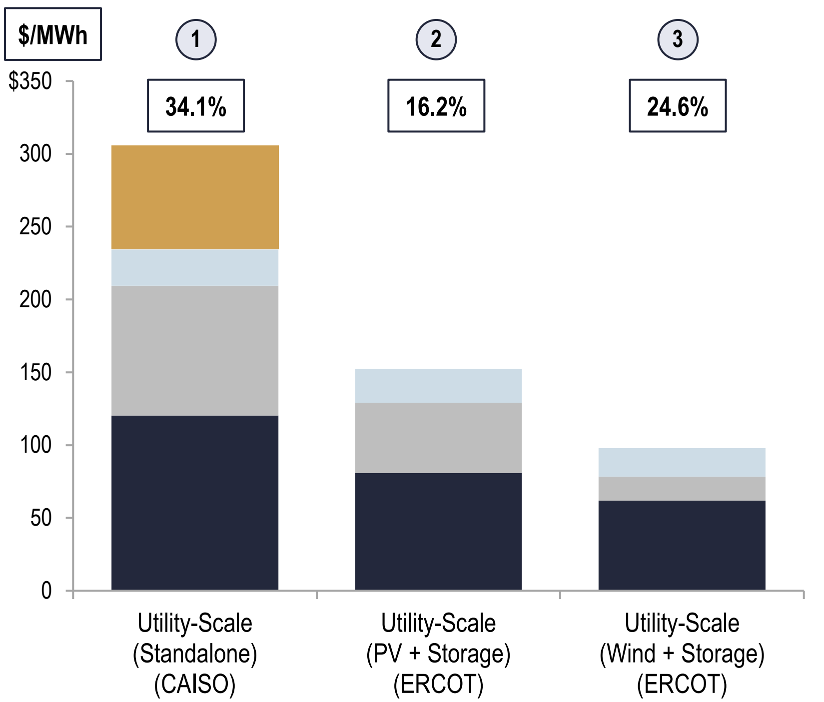
Project size: 50 MW / 200 MWh
100 MW Wind

Source: Lazard and Roland Berger estimates, Enovation Analytics and publicly available information.
Note: Project parameters (i.e., battery size, duration, etc.) presented above correspond to the inputs used in the LCOS analysis.
(1) Assumes the project provides services under contract with PG&E.
(2) Assumes the project provides services under contract with HECO.

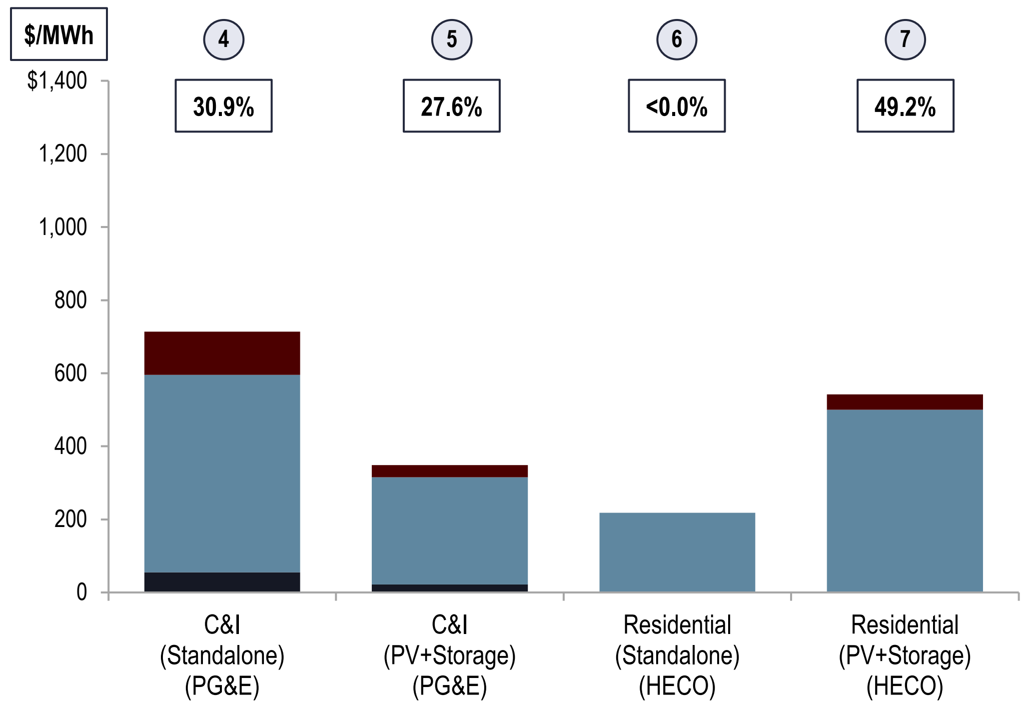
Value Snapshot Case Studies—Summary Results

Project economics evaluated in the Value Snapshot analysis continue to evolve year-over-year as costs change and the value of revenue streams adjust to reflect underlying market conditions, utility rate structures and policy developments

In-Front-of-the-Meter Revenue



Behind-the-Meter Revenue



Wholesale Energy Sales | Frequency Regulation | Spinning/Non-spinning Reserves | Resource Adequacy | Demand Response—Utility | Bill Management | Local Incentive Payments | Subsidized IRR

Source: *Lazard and Roland Berger estimates, Enovation Analytics and publicly available information.*

Note: Levelized costs presented for each Value Snapshot reflect local market and operating conditions (including installed costs, market prices, charging costs and incentives) and are different in certain cases from the LCOS results for the equivalent use case on the pages titled "Levelized Cost of Storage Comparison—Energy ($/MWh)", which are more broadly representative of U.S. storage market conditions versus location-specific. Levelized revenues in all cases show gross revenues (not including charging costs) to be comparable with the levelized cost, which incorporates charging costs. Subsidized levelized cost for each Value Snapshot reflects: (1) average cost structure for storage, solar and wind capital costs, (2) charging costs based on local wholesale prices or utility tariff rates and (3) all applicable state and federal tax incentives, including 30% federal ITC for solar, 30% federal ITC for storage, $26/MWh federal PTC for wind and 35% Hawaii state ITC for solar and solar + storage systems. Value Snapshots do not include cash payments from state or utility incentive programs. Revenues for Value Snapshots (1) – (3) are based on hourly wholesale prices from the 365 days prior to Dec. 15, 2022. Revenues for Value Snapshots (4) – (6) are based on the most recent tariffs, programs and incentives available as of December 2022.

LCOE+

III Lazard's Levelized Cost of Hydrogen Analysis—Version 3.0

Introduction

Lazard's Levelized Cost of Hydrogen ("LCOH") analysis addresses the following topics:

- **An overview of the current commercial context for hydrogen in the U.S.**
- **Comparative and illustrative LCOH analysis for various hydrogen power production systems on a $/kg basis**
- **Comparative and illustrative LCOE analysis for gas peaking generation, a key use case in the U.S. power sector, utilizing a 25% blend of Green and Pink hydrogen on a $/MWh basis, including sensitivities for U.S. federal tax subsidies**
- **Appendix materials, including:**
  - An overview of the methodology utilized to prepare Lazard's LCOH analysis
  - A summary of the assumptions utilized in Lazard's LCOH analysis

Other factors would also have a potentially significant effect on the results contained herein, but have not been examined in the scope of this current analysis. These additional factors, among others, could include: implementation and interpretation of the full scope of the IRA; development costs of the electrolyzer and associated renewable energy generation facility; conversion, storage and transportation costs of the hydrogen once produced; additional costs to produce alternate products (e.g., ammonia); costs to upgrade existing infrastructure to facilitate the transportation of hydrogen (e.g., natural gas pipelines); electrical grid upgrades; costs associated with modifying end-use infrastructure/equipment to use hydrogen as a fuel source; potential value associated with carbon-free fuel production (e.g., carbon credits, incentives, etc.). This analysis also does not address potential environmental and social externalities, including, for example, water consumption and the societal consequences of displacing the various conventional fuels with hydrogen that are difficult to measure

As a result of the developing nature of hydrogen production and its applications, it is important to have in mind the somewhat limited nature of the LCOH (and related limited historical market experience and current market depth). In that regard, we are aware that, as a result of our data collection methodology, some will have a view that electrolyzer cost and efficiency, plus electricity costs, suggest a different LCOH than what is presented herein. The sensitivities presented in our study are intended to address, in part, such views

Note: This report has been compiled using U.S.-focused data.

Lazard's Levelized Cost of Hydrogen ("LCOH") Analysis—Executive Summary

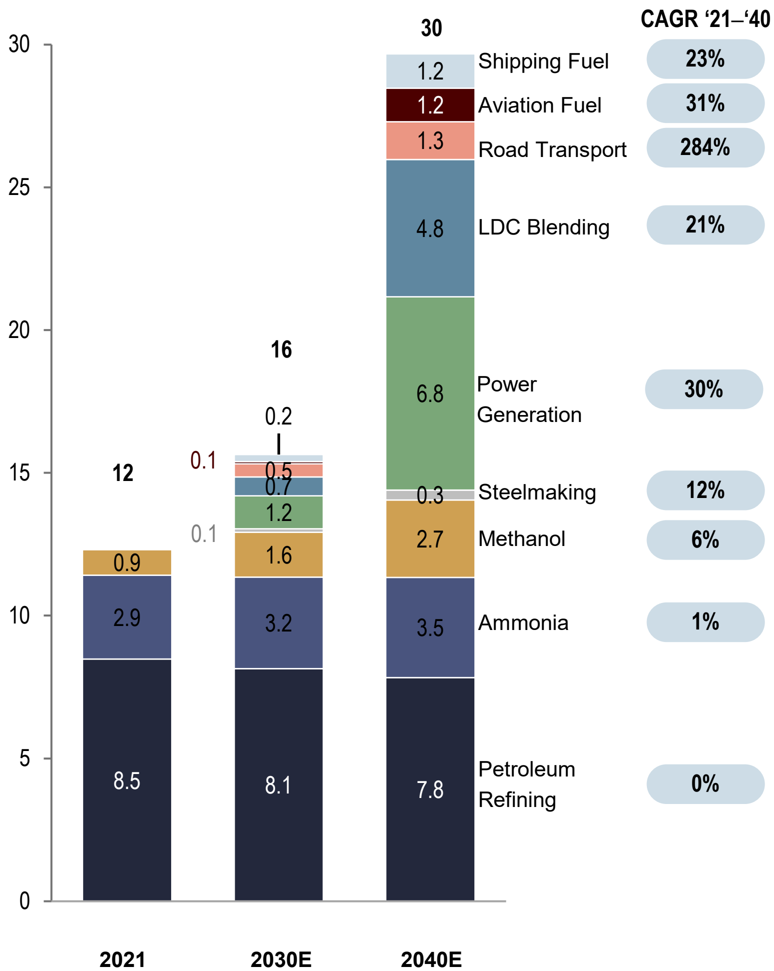
Technology Overview & Commercial Readiness	<u>Hydrogen and Hydrogen Production</u> • Hydrogen is currently produced primarily from fossil fuels using steam-methane reforming and methane splitting processes (i.e., "Gray" hydrogen) • A variety of additional processes are available to produce hydrogen from electricity and water (called electrolysis), which are at varying degrees of development and commercial viability, but the two most discussed forms of electrolysis are alkaline and PEM • Alkaline is generally best for large-scale industrial installations requiring a steady H_2 output at low pressure while PEM is generally well-suited for off-grid installations powered by highly variable renewable energy sources <u>Hydrogen for Power Generation</u> • Combustion turbines for 100% hydrogen are not commercially available today. Power generators are exploring blending with natural gas as a way to reduce carbon intensity • Several pilots and studies are being conducted and planned in the U.S. today. Most projects include up to 5% hydrogen blend by volume, but some testing facilities have used blends of over 40% hydrogen by volume • Hydrogen for power generation can occur via two different combustion methods: (1) premixed systems (or Dry, Low-NOx ("DLN") systems) that mix fuel and air upstream before combustion which lowers required temperature and NOx emissions and (2) non-mixed systems that combust fuel and air without premixing which requires water injection to lower NOx emissions
Market Activity & Policy Support	• Hydrogen is currently used primarily in industrial applications, including oil refining, steel production, ammonia and methanol production and as feedstock for other smaller-scale chemical processes • Clean hydrogen is well-positioned to reduce CO_2 emissions in typically "hard-to-decarbonize" sectors such as cement production, centralized energy systems, steel production, transportation and mobility (e.g., forklifts, maritime vessels, trucks and buses) • Natural gas utilities are likely to be early adopters of Green hydrogen as methanation (i.e., combining hydrogen with CO_2 to produce methane) becomes commercially viable and pipeline infrastructure is upgraded to support hydrogen blends • The IRA provides a distinct policy push to grow hydrogen production through the hydrogen PTC and ITC. In addition, clean hydrogen would see added lifts from tax and other benefits aimed at clean generation technologies
Future Perspectives	• Given its versatility as an energy carrier, hydrogen has the potential to be used across industrial processes, power generation and transportation, creating a potential path for decarbonizing energy-intensive industries where current technologies/alternatives are not presently viable • Clean hydrogen is expected to play a significant role in decarbonizing U.S. energy and other industries, including power generation through combustion, feedstock for ammonia, refining processes and e-fuels
Overview of Analysis	• The LCOH illustratively compares hydrogen produced through electrolysis via renewable power (Green) and nuclear power (Pink) • The analysis also includes the LCOE impact of blending these hydrogen sources with natural gas for power generation • For the analysis, unsubsidized renewables pricing is based on the average LCOE of a wind plant, oversized as compared to the electrolyzer and accounting for costs of curtailment. Unsubsidized nuclear power pricing is based on the average LCOE for an existing nuclear plant • Subsidized costs include the impact of the IRA. The IRA is comprehensive legislation that is still being implemented and remains subject to interpretation—important elements of the IRA are not included in our analysis and could impact outcomes

Source: Lazard and Roland Berger estimates and publicly available information.

Hydrogen Applications in Today's Economy

Today, most hydrogen is produced using fossil sources (i.e., Gray hydrogen) and is used primarily in refining and chemicals sectors, but clean (i.e., Blue, Green or Pink) hydrogen is expected to play an important role in several new growth sectors, including power generation

Forecasted U.S. Hydrogen Demand (million tons)



Key Hydrogen Terms and Implications for the Power Sector

Overview of Hydrogen Color Spectrum

- Hydrogen production can be divided into "conventional" and "clean" hydrogen:
  - **Conventional**:
    - Gray: Almost all hydrogen produced in the U.S. today is through steam-methane reforming, where hydrogen is separated from natural gas. Carbon dioxide is a byproduct of this process
    - **Black (or Brown)**: Uses steam and oxygen to break molecules in coal into a gaseous mixture resulting in streams of hydrogen and carbon dioxide
  - A catch-all, **Yellow** hydrogen is produced through electrolysis using grid electricity
  - "Clean" hydrogen comes in several colors, which are based on the production process, including:
    - **Blue:** Black, Brown or Gray hydrogen, but with carbon emissions captured or stored
    - **Green:** Renewable power used for electrolysis, where water molecules are split into hydrogen and oxygen using electricity
    - **Pink:** Nuclear power used for electrolysis
  - Other novel production processes include **Turquoise** hydrogen from methane pyrolysis, which uses thermal splitting of methane into hydrogen and solid carbon and is considered carbon-free if using electricity from renewable sources

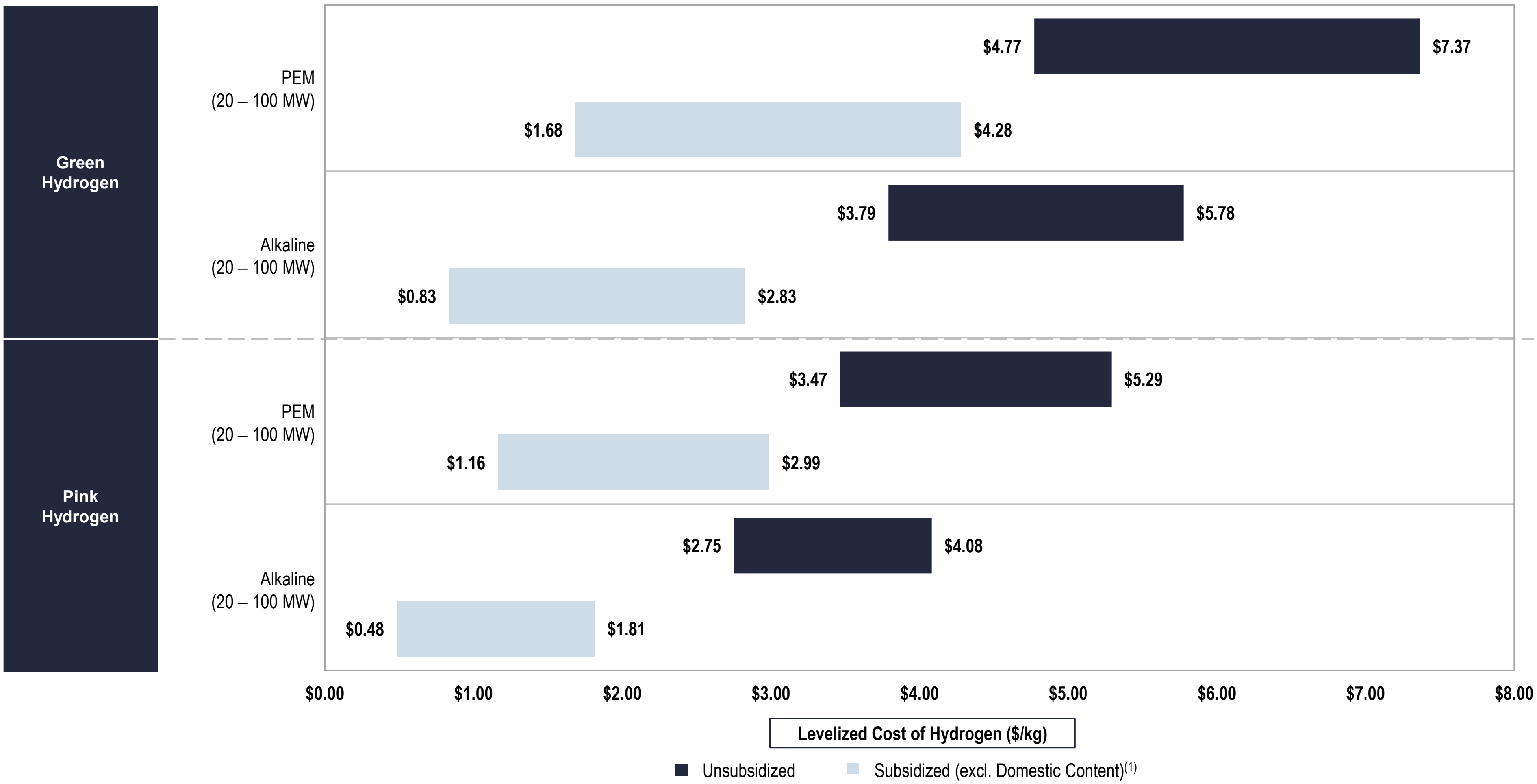
Implications for the Power Sector

- Several utilities and developers have started exploring co-firing clean hydrogen with natural gas in combustion turbines to reduce emissions
- Clean hydrogen production as a method to store renewable energy could utilize what would otherwise be curtailed renewable load and turn this energy into carbon-free dispatchable load, allowing for higher penetration of intermittent renewable resources, while also impacting capacity market prices and seasonal pricing peaks

Source: Lazard and Roland Berger estimates and publicly available information.

Levelized Cost of Hydrogen Analysis—Illustrative Results

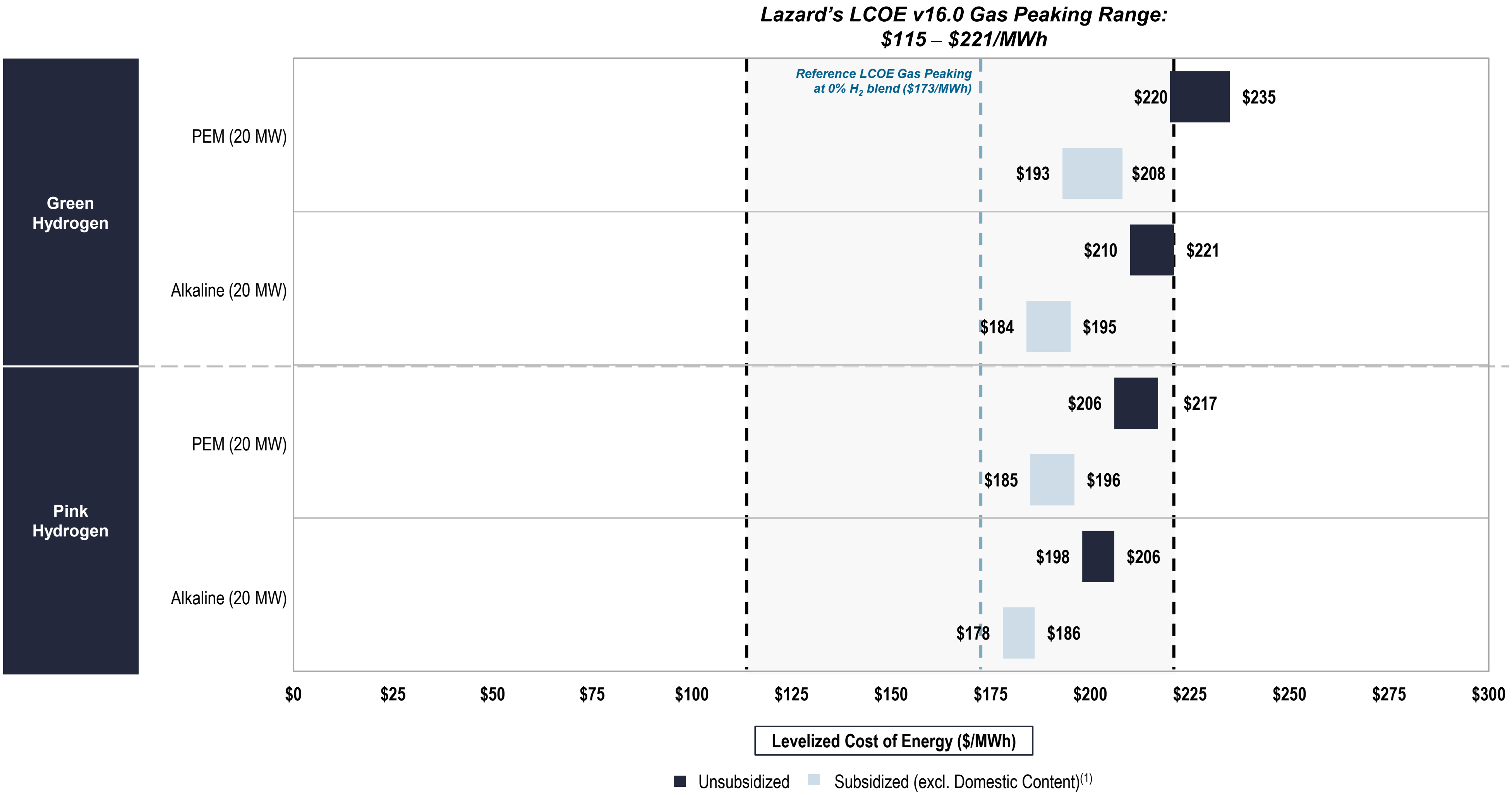
Subsidized Green and Pink hydrogen can reach levelized production costs under $2/kg—fully depreciated operating nuclear plants yield higher capacity factors and, when only accounting for operating expenses, Pink can reach production levels lower than Green hydrogen



Source: *Lazard and Roland Berger estimates and publicly available information.*
Note: Here and throughout this presentation, unless otherwise indicated, this analysis assumes electrolyzer capital expenditure assumptions based on high and low values of sample ranges, with additional capital expenditure for hydrogen storage. Capital expenditure for underground hydrogen storage assumes $20/kg storage cost, sized at 120 tons for Green H_2 and 200 tons for Pink H_2 (size is driven by electrolyzer capacity factors). Pink hydrogen costs are based on marginal costs for an existing nuclear plant (see Appendix for detailed assumptions).
(1) This sensitivity analysis assumes that projects qualify for the full PTC and have a capital structure that includes sponsor equity, debt and tax equity. The IRA is comprehensive legislation that is still being implemented and remains subject to interpretation—important elements of the IRA are not included in our analysis and could impact outcomes.

Levelized Cost of Energy—Gas Peaking Plant with 25% Hydrogen Blend

While hydrogen-ready natural gas turbines are still being tested, preliminary results, including our illustrative LCOH analysis, indicate that a 25% hydrogen by volume blend is feasible and cost competitive



Source: *Lazard and Roland Berger estimates and publicly available information.*

Note: The analysis presented herein assumes a fuel blend of 25% hydrogen and 75% natural gas. Results are driven by Lazard's approach to calculating the LCOE and selected inputs (see Appendix for further details). Natural gas fuel cost assumed \$3.45/MMBtu, hydrogen fuel cost based on LCOH \$/kg for case scenarios, assumes 8.8 kg/MMBtu for hydrogen. Analysis includes hydrogen storage costs for a maximum of 8 hour peak episodes for a maximum of 7 days per year, resulting in additional costs of \$120/kW (Green) and \$190/kW (Pink).

(1) This sensitivity analysis assumes that projects qualify for the full PTC and have a capital structure that includes sponsor equity, debt and tax equity. The IRA is comprehensive legislation that is still being implemented and remains subject to interpretation—important elements of the IRA are not included in our analysis and could impact outcomes.

Appendix

A Maturing Technologies

Introduction

Lazard's preliminary perspectives on selected maturing technologies addresses the following topics:

- **Lazard's Carbon Capture & Storage ("CCS") System perspectives**
  - An overview of key findings and observed trends in the CCS sector
  - A comparative levelized cost of CCS for power generation on a $/MWh basis, including selected sensitivities for U.S. federal tax subsidies
  - An illustrative view of the value-add of CCS when included as an element of a new-build and retrofitted combined cycle gas plant
  - A comparison of capital costs on a $/kW basis for both new-build natural gas plants with CCS technology and existing natural gas plants retrofitted with CCS technology
- **Lazard's Long Duration Energy Storage ("LDES") analysis**
  - An overview of key findings and observed trends in the LDES sector
  - A comparative levelized cost for three selected types of LDES technologies, including selected sensitivities for U.S. federal tax subsidies

Other factors would also have a potentially significant effect on the results contained herein, but have not been examined in the scope of this current analysis. These additional factors, among others, could include: implementation and interpretation of the full scope of the IRA; development costs of the carbon capture or LDES system or associated generation facility; conversion, storage or transportation costs of the CO_2 once past the project site; costs to upgrade existing infrastructure to facilitate the transportation of CO_2; potential value associated with carbon-free fuel production (e.g., carbon credits, incentives, etc.); potential value associated with energy storage revenue (e.g., capacity payments, demand response, energy arbitrage, etc.); network upgrades, transmission, congestion or other integration-related costs; permitting or other development costs, unless otherwise noted; and costs of complying with various regulations (e.g., federal import tariffs or labor requirements). This analysis also does not address potential environmental and social externalities, including, for example, water consumption and the societal consequences of storing or transporting CO_2, material mining and land use

Importantly, this analysis is preliminary in nature, largely directional and does not fully take into account the maturing nature of the technologies analyzed herein

Note: This report has been compiled using U.S.-focused data.

1 Carbon Capture & Storage Systems

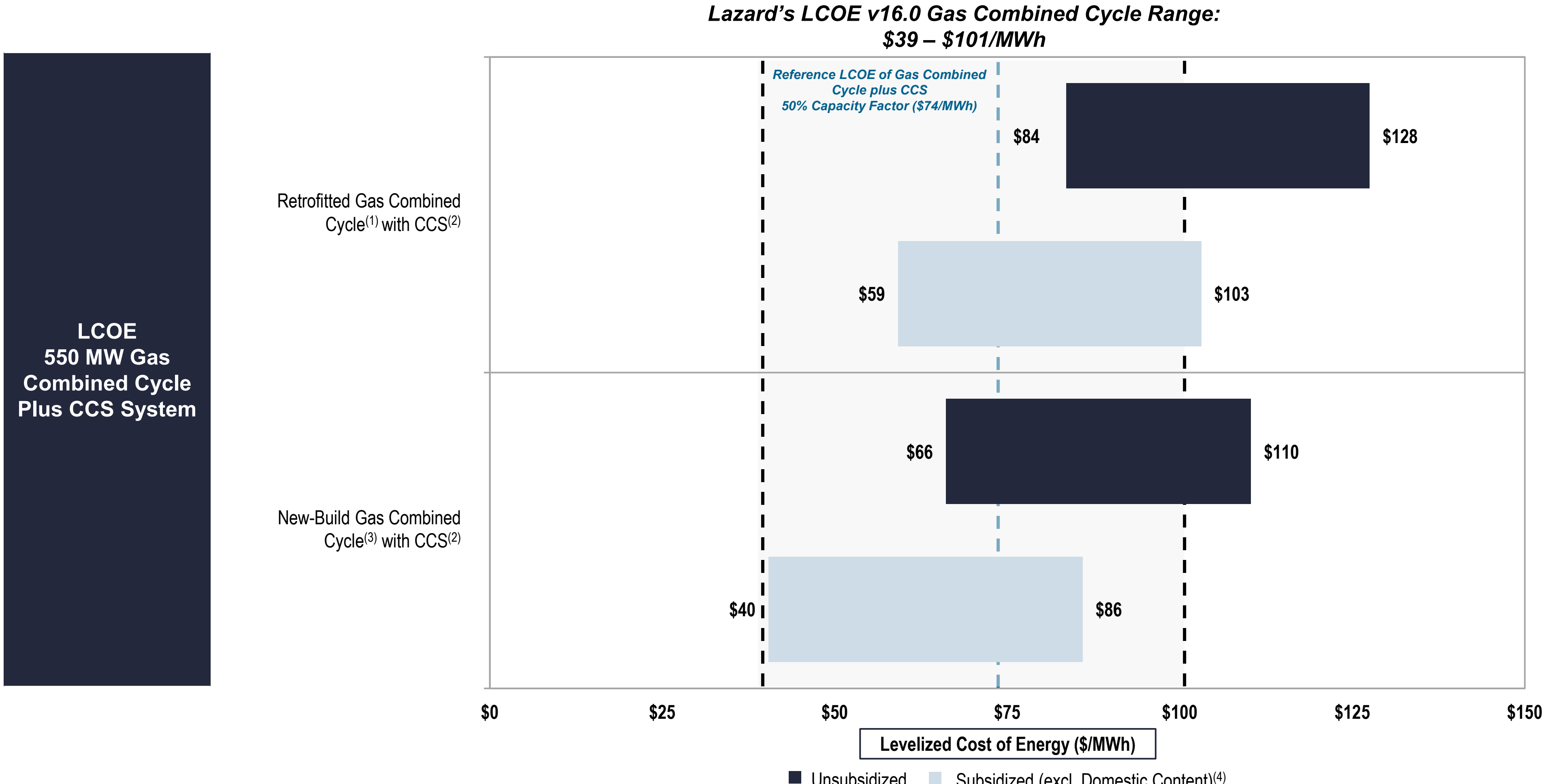
Lazard's Carbon Capture & Storage Analysis—Executive Summary

Technology Overview & Commercial Readiness	• CCS refers to technologies designed to sequester carbon dioxide emissions, particularly from power generation or industrial sources • The core technology involves a specialized solvent or other material that enables the capture of carbon dioxide from a gas stream (usually an exhaust gas) • Oxycombustion is emerging as a potential new type of natural gas power plant design that integrates CO_2 capture in the combustion cycle for a claimed 100% capture rate • In power generation, CCS can be applied as a retrofit to existing coal and gas-fired power plants or incorporated into new-build plants • CO_2 capture rates are currently 80% – 90%, with a near-term goal of 95%+ • Current "post-combustion" CCS technologies require power plants to operate close to full load in order to maintain high capture rates • CCS systems require energy input and represent a parasitic load on the generation unit effectively increasing the "heat rate" of the generator • CCS also requires compression, transportation and either secure permanent underground storage of carbon dioxide or alternate end-use • To date, there are very few completed power generation CCS project examples
Market Activity & Policy Support	• CCS has attracted significant interest and investment from various market participants • Project costs, especially for retrofits, are highly dependent upon site characteristics • The Department of Energy ("DOE")/National Energy Technology Laboratory ("NETL") have provided significant support for the emerging CCS sector by funding engineering studies and collecting cost estimates and performance data • The IRA has increased the tax credit for carbon sequestration to \$85/ton, providing a significant subsidy for CCS deployment that can offset much of the increased capital and operating costs of a CCS retrofit or new-build with CCS • A number of power sector CCS projects are being developed to retrofit existing coal and natural gas power plants, some of which are expected to be completed by the middle of the decade
Future Perspectives	• Natural gas power generation will continue to play an important role in grid reliability, especially as renewable penetration increases and more coal retires • CCS has the potential to allow natural gas plants to remain in operation as the U.S. continues to rapidly decarbonize its power grid • CCS costs are still high, and given that the majority of the capital cost of a CCS system consists of balance-of-system components, innovations in solvents and other core capture technologies may not result in significant cost reductions • New technologies such as oxycombustion systems may represent meaningful improvements in capture efficiency and cost • The deployment of any CCS technology depends on the availability of either offtake or permanent CO_2 storage reservoirs (placing geographic limitations on deployment) and the validation of the security of permanent storage (in avoiding CO_2 leakage)
Overview of Analysis	• The illustrative analysis presented herein is limited to post-combustion CCS for power generation • Two cases are included: (1) an amine CCS system retrofitted to an existing natural gas combined cycle plant and (2) an amine CCS system with a new-build natural gas combined cycle plant • CO_2 transportation and storage costs are assumed to be fixed across both cases at \$23/ton • Subsidized costs include the impact of the IRA. The IRA is comprehensive legislation that is still being implemented and remains subject to interpretation—important elements of the IRA are not included in our analysis and could impact outcomes

Source: Lazard and Roland Berger estimates and publicly available information.

Levelized Cost of Energy—Gas Combined Cycle + CCS System

CCS systems benefit from federal subsidies through the IRA, making the LCOE of a gas combined cycle plant plus a CCS system cost-competitive with a standalone gas combined cycle plant in both a retrofit and new-build scenario



Source: *Lazard and Roland Berger estimates and publicly available information.*

Note: The fuel cost assumption for Lazard's analysis for gas-fired generation resources is $3.45/MMBTU.

(1) Represents the LCOE of a combined system, new CCS with a useful life of 12 years and LCOE of Gas Combined Cycle including remaining book value of retrofitted power plant. The low case represents an 85% capacity factor while the high case represents a 50% capacity factor.

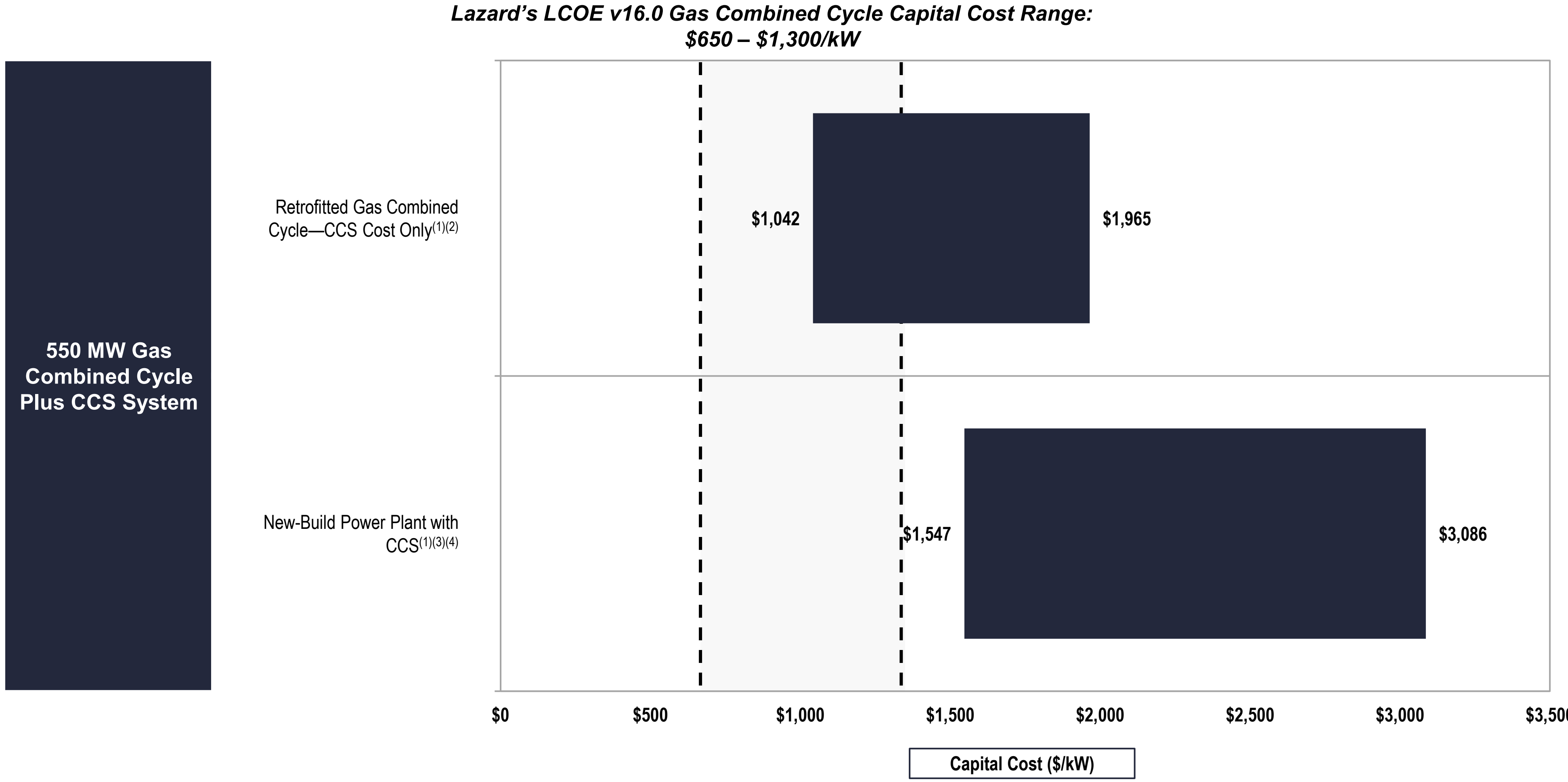
(2) Represents a 2 million-ton CO_2 plant and generation heat rate increases of 11% for the low case (85% capacity factor) and 21% for the high case (50% capacity factor) due to fixed usage of parasitic power by the CCS equipment.

(3) Represents the LCOE of a combined system with a useful life of 20 years. The low case represents an oxycombustion CCS system with a capacity factor of 92.5% and a $10/MWh benefit for industrial gas sales. The high case represents a Gas Combined Cycle + CCS with a capacity factor of 50% and a $2.50/MWh benefit for industrial gas sales.

(4) Subsidized value assumes $85/ton CO_2 credit for 12 years with nominal carbon capture rate of 95% for Gas Combined Cycle + CCS and 100% nominal capture rate for oxycombustion. Assumes an emissions rate of 0.41 ton CO_2 per MWh generated. All costs include a $23/ton CO_2 cost of transportation and storage. There is no domestic content adder available for the CO_2 tax credit. The IRA is comprehensive legislation that is still being implemented and remains subject to interpretation—important elements of the IRA are not included in our analysis and could impact outcomes.

Carbon Capture & Storage Systems—Capital Cost Comparison (Unsubsidized)

CCS costs are still high and the majority of the capital cost of a CCS system consists of balance-of-system components



Source: Lazard and Roland Berger estimates and publicly available information.
(1) Represents an assumed 2-million-ton CO_2 plant and 550 MW Gas Combined Cycle generation at 85% capacity factor.
(2) Represents an assumed \$440 – \$550/ton CO_2 of nameplate capacity CCS system.
(3) Represents an assumed \$700 – \$1,300/kW for Gas Combined Cycle and \$400 – \$500/ton CO_2 of nameplate capacity for CCS.
(4) New-build range also includes a capital expenditure estimate for a 280 MW oxycombustion project.

2 Long Duration Energy Storage

Lazard's Long Duration Energy Storage Analysis—Executive Summary

Technology Overview & Commercial Readiness	• LDES technologies are emerging alternatives to lithium-ion batteries because they have the potential to be more economical at storage durations of 6 – 8+ hours • Technological categories include electrochemical (including flow batteries and other non-lithium chemistries), mechanical (including compressed air storage) and thermal • A key challenge for LDES economics is the round-trip efficiency or the percentage of the stored energy that can later be output. Currently, LDES technologies have round trip efficiencies, which are varied but generally less than the 85% – 90% for lithium-ion battery systems • LDES technologies generally do not rely on scarce or expensive mineral inputs, but they can require increased engineering, labor and site work compared to lithium-ion, particularly for mechanical storage solutions • Most LDES technologies have not yet reached commercialization due to technology immaturity and, with limited deployments, seemingly none of the emerging LDES technologies have achieved the track record for performance required to be fully bankable
Market Activity & Policy Support	• Emerging LDES technology companies have attracted significant capital investment in the past 5 years • To date, LDES deployments have generally been limited to pilot/early commercial scale • LDES providers are generally seeking to reach commercial manufacturing scale by the end of the decade to be able to support grid-scale deployments that are cost-competitive • The U.S. DOE's concerted funding initiatives, along with the IRA ITC for energy storage resources support and somewhat de-risk LDES deployment • LDES technologies are divorced from the lithium-ion/electric vehicle supply chain, which may confer attractiveness in the short term given increased lithium costs and ongoing supply chain concerns • However, Industry participants are still evaluating the system need for long duration storage as well as appropriate market mechanisms and signals
Future Perspectives	• At increasingly high wind and solar penetrations, there will be a need for resources that can provide capacity over longer durations in order to meet overall capacity and reliability requirements • LDES technologies could potentially serve this function and enable higher levels of decarbonized power generation as a substitute for traditional "peaking" resources • Market structures and pricing signals may be established/adopted to reflect identified value of longer duration storage resources • LDES technologies will compete with, among other things, green hydrogen (generation and storage), natural gas generators with carbon capture systems and advanced nuclear reactors to provide capacity to a decarbonized power grid (assuming viability/acceptability of the relevant LDES technologies)
Overview of Analysis	• The illustrative analysis presented herein includes non-lithium technologies and compares the levelized costs of several flow battery cases along with a compressed air energy system ("CAES") case • All systems are 100 MW, 8 hour systems with one cycle per day at maximum charge and depth of discharge (maximum stored energy output given round trip efficiency) • Subsidized costs include the impact of the IRA. The IRA is comprehensive legislation that is still being implemented and remains subject to interpretation—important elements of the IRA are not included in our analysis and could impact outcomes

Source: Lazard and Roland Berger estimates and publicly available information.

Long Duration Energy Storage Technologies—Overview

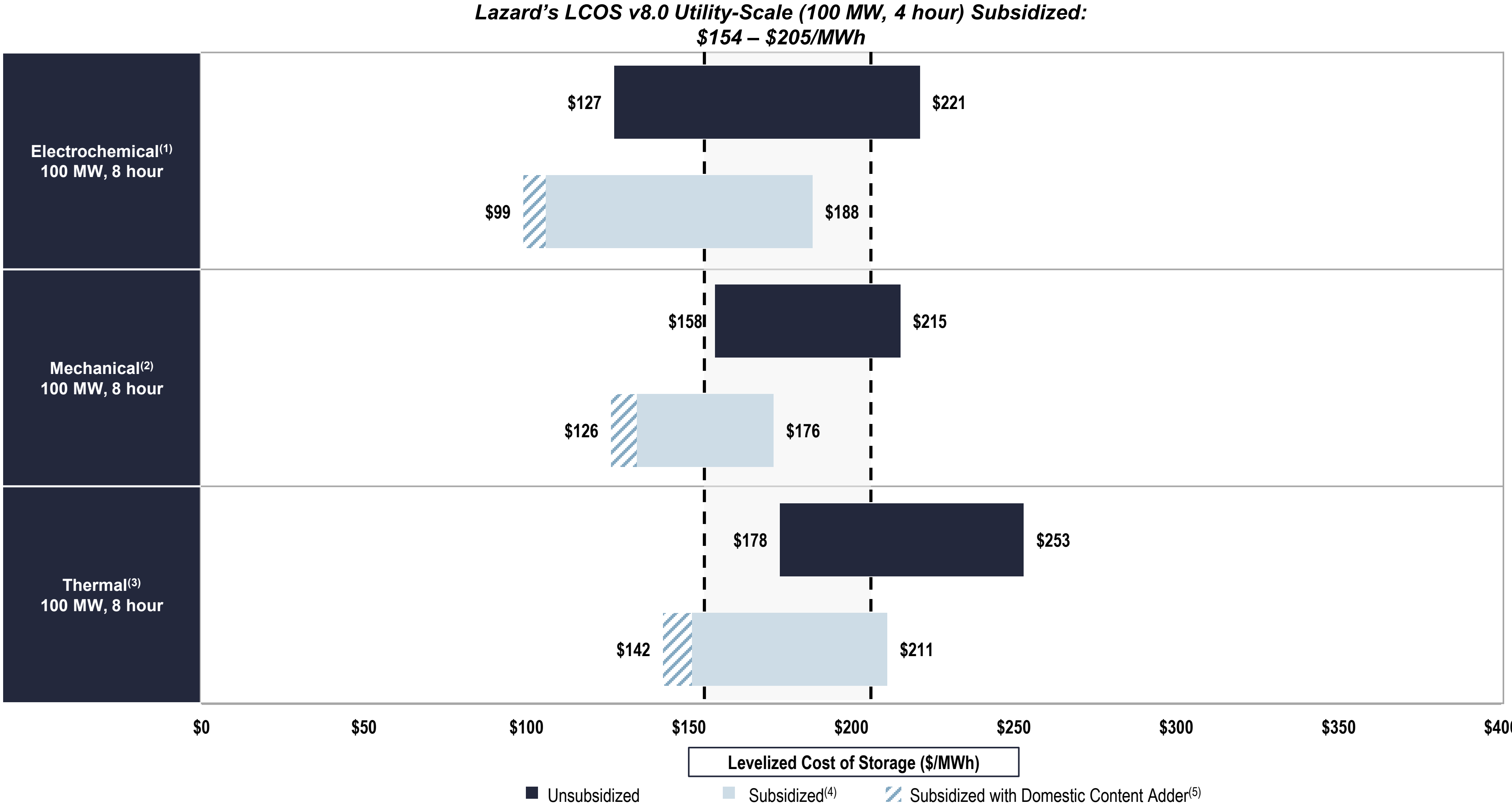
LDES technologies typically fall into three main technological categories that provide unique advantages and disadvantages and also make them suitable (or not) across a variety of use cases

	Electrochemical	Mechanical	Thermal
Description	• Energy storage systems generating electrical energy from chemical reactions	• Solutions that store energy as a kinetic, gravitational potential or compression/pressure medium	• Solutions stocking thermal energy by heating or cooling a storage medium
Typical Technologies	• Flow batteries (vanadium, zinc-bromide) • Sodium-sulfur • Iron-air	• Adiabatic and cryogenic compressed liquids (change in internal energy) • Geo-mechanical pumped hydro • Gravitational	• Latent heat (phase change) • Sensible heat (molten salt)
Selected Advantages	• No degradation • Cycling throughout the day • Modular options available • Considered safe	• Considered safe • Attractive economics • Proven technologies (e.g., pumped hydro)	• Able to leverage mature industrial cryogenic technology base • Inexpensive materials • Power/energy independent • Scalable
Selected Disadvantages	• Membrane materials costly • Difficult to mass produce • Scalability unclear	• Large volumetric storage sites • Difficult to modularize • Cycling typically limited to once per day	• Reduced energy density • Cryogenic safety concerns • Cannot modularize after install
Key Challenges	• Expensive ion-exchange membranes required due to voltage and electrolyte stress • Less compact (lower energy density)	• Geographic limitations of some sub-technologies • Low efficiency of diabatic systems	• Visibility into peak and off-peak • Climate impact on effectiveness • Scale of application (e.g., best for district heating)

Source: Lazard and Roland Berger estimates and publicly available information.

Levelized Cost of Energy—Illustrative LDES at Scale

The LCOE of LDES technologies is expected to be competitive with lithium-ion for large-scale 8 hour systems in the second half of the decade, with anticipated unit cost advantages at longer durations overcoming lower round-trip efficiency



Source: *Lazard and Roland Berger estimates and publicly available information.*
Note: All cases assume a 20-year system life and 1 cycle per day at maximum depth-of-discharge.
(1) Electrochemical includes flow batteries (vanadium redox, zinc bromine) and non-flow (liquid metal).
(2) Mechanical includes CAES and liquified air energy storage ("LAES").
(3) Thermal includes sensible heat storage solutions (molten salt).
(4) This sensitivity analysis assumes that projects qualify for the full standalone storage ITC.
(5) This sensitivity analysis assumes the above and also includes a 10% domestic content adder. The IRA is comprehensive legislation that is still being implemented and remains subject to interpretation—important elements of the IRA are not included in our analysis and could impact outcomes.

B LCOE v16.0

Levelized Cost of Energy Comparison—Methodology

($ in millions, unless otherwise noted)

Lazard's LCOE analysis consists of creating a power plant model representing an illustrative project for each relevant technology and solving for the $/MWh value that results in a levered IRR equal to the assumed cost of equity (see subsequent "Key Assumptions" pages for detailed assumptions by technology)

Unsubsidized Onshore Wind — Low Case Sample Illustrative Calculations

Year[1]		*0*	*1*	*2*	*3*	*4*	*5*	*6*	*7*	*20*
Capacity (MW)	(A)		175	175	175	175	175	175	175	175
Capacity Factor	(B)		55%	55%	55%	55%	55%	55%	55%	55%
Total Generation ('000 MWh)	(A) x (B) = (C)*		843	843	843	843	843	843	843	843
Levelized Energy Cost ($/MWh)	***(D)***		***$24.4***	***$24.4***	***$24.4***	***$24.4***	***$24.4***	***$24.4***	***$24.4***	***$24.4***
Total Revenues	**(C) x (D) = (E)***		**$20.6**	**$20.6**	**$20.6**	**$20.6**	**$20.6**	**$20.6**	**$20.6**	**$20.6**
Total Fuel Cost	(F)		--	--	--	--	--	--	--	--
Total O&M	(G)*		3.5	3.6	3.7	3.7	3.8	3.9	4.0	5.5
Total Operating Costs	**(F) + (G) = (H)**		**$3.5**	**$3.6**	**$3.7**	**$3.7**	**$3.8**	$3.9	$4.0	$5.5
EBITDA	**(E) - (H) = (I)**		**$17.1**	**$17.0**	**$16.9**	**$16.8**	**$16.7**	**$16.7**	**$16.6**	**$15.1**
Debt Outstanding - Beginning of Period	(J)		$107.6	$105.5	$103.2	$100.7	$98.0	$95.1	$92.0	$9.9
Debt - Interest Expense	(K)		(8.6)	(8.4)	(8.3)	(8.1)	(7.8)	(7.6)	(7.4)	(0.8)
Debt - Principal Payment	(L)		(2.1)	(2.3)	(2.5)	(2.7)	(2.9)	(3.1)	(3.4)	(9.9)
Levelized Debt Service	(K) + (L) = (M)		($10.7)	($10.7)	($10.7)	($10.7)	($10.7)	($10.7)	($10.7)	($10.7)
EBITDA	**(I)**		$17.1	$17.0	$16.9	$16.8	$16.7	$16.7	$16.6	$15.1
Depreciation (MACRS)	(N)		(35.9)	(57.4)	(34.4)	(20.7)	(20.7)	(10.3)	0.0	0.0
Interest Expense	(K)		(8.6)	(8.4)	(8.3)	(8.1)	(7.8)	6.3	16.6	(0.8)
Taxable Income	**(I) + (N) + (K) = (O)**		**($27.4)**	**($48.8)**	**($25.8)**	**($11.9)**	**($11.8)**	**($7.6)**	**($7.4)**	**$14.3**
Federal Production Tax Credit Value	(P)		$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Federal Production Tax Credit Received	(P) x (C) = (Q)*		$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Tax Benefit (Liability)	**(O) x (tax rate) + (Q) = (R)**		**$11.0**	**$19.5**	**$10.3**	**$4.8**	**$4.7**	**$0.0**	**$0.0**	**$0.0**
Capital Expenditures		**($71.8)**	**($107.6)**	**$0.0**	**$0.0**	**$0.0**	**$0.0**	**$0.0**	**$0.0**	**$0.0**
After-Tax Net Equity Cash Flow[2]	**(I) + (M) + (R) = (S)**	**($71.8)**[3]	**$17.3**	**$25.8**	**$16.5**	**$10.8**	**$10.7**	**$0.0**	**$0.0**	**($1.4)**
Cash Flow to Equity Investors	(S) x (% to Equity Investors)	($71.8)	$17.3	$25.8	$16.5	$10.8	$10.7	$6.4	$2.1	($1.4)
IRR For Equity Investors		**12.0%**								

Key Assumptions[4]	
Capacity (MW)	175
Capacity Factor	55%
Fuel Cost ($/MMBtu)	$0.00
Heat Rate (Btu/kWh)	0
Fixed O&M ($/kW-year)	$20.0
Variable O&M ($/MWh)	$0.0
O&M Escalation Rate	2.25%
Capital Structure	
Debt	60.0%
Cost of Debt	8.0%
Tax Investors	0.0%
Cost of Equity for Tax Investors	10.0%
Equity	40.0%
Cost of Equity	12.0%
Taxes and Tax Incentives:	
Combined Tax Rate	40%
Economic Life (years)[5]	20
MACRS Depreciation (Year Schedule)	5
PTC (+10% for Domestic Content)	$0.0
PTC Escalation Rate	1.5%
Capex	
EPC Costs ($/kW)	$1,025
Additional Owner's Costs ($/kW)	$0
Transmission Costs ($/kW)	$0
Total Capital Costs ($/kW)	$1,025
Total Capex ($mm)	$179
Cash Flow Distribution	
Portion to Tax Investors (After Return is Met)	1%

Technology-dependent

Levelized

Source: *Lazard and Roland Berger estimates and publicly available information.*
Note: Onshore Wind—Low LCOE case presented for illustrative purposes only.
* Denotes unit conversion.
(1) Assumes half-year convention for discounting purposes.
(2) Assumes full monetization of tax benefits or losses immediately.
(3) Reflects initial cash outflow from equity investors.
(4) Reflects a "key" subset of all assumptions for methodology illustration purposes only. Does not reflect all assumptions.
(5) Economic life sets debt amortization schedule. For comparison purposes, all technologies calculate LCOE on a 20-year IRR basis.

Levelized Cost of Energy—Key Assumptions

		Solar PV							
		Rooftop—Residential		Community and C&I		Utility-Scale		Utility Scale + Storage	
	Units	Low Case	High Case	Low Case	High Case	Low Case	High Case	Low Case	High Case
Net Facility Output	MW	0.005		5		150		100	
Total Capital Costs[(1)]	$/kW	$2,230 –	$4,150	$1,200 –	$2,850	$700 –	$1,400	$1,075 –	$1,600
Fixed O&M	$/kW-yr	$15.00 –	$18.00	$12.00 –	$18.00	$7.00 –	$14.00	$20.00 –	$45.00
Variable O&M	$/MWh	—		—		—		—	
Heat Rate	Btu/kWh	—		—		—		—	
Capacity Factor	%	20% –	15%	25% –	15%	30% –	15%	27% –	20%
Fuel Price	$/MMBTU	—		—		—		—	
Construction Time	Months	3		4 –	6	9		9	
Facility Life	Years	25		30		30		30	
Levelized Cost of Energy	$/MWh	$117 –	$282	$49 –	$185	$24 –	$96	$46 –	$102

Source: *Lazard and Roland Berger estimates and publicly available information.*

(1) Includes capitalized financing costs during construction for generation types with over 12 months of construction time.

Levelized Cost of Energy—Key Assumptions (cont'd)

	Units	Geothermal[1]		Wind—Onshore		Wind—Onshore + Storage		Wind—Offshore	
		Low Case	High Case	Low Case	High Case	Low Case	High Case	Low Case	High Case
Net Facility Output	MW	250		175		100		1000	
Total Capital Costs[2]	$/kW	$4,700	$6,075	$1,025	$1,700	$1,375	$2,250	$3,000	$5,000
Fixed O&M	$/kW-yr	$14.00	$15.25	$20.00	$35.00	$32.00	$80.00	$60.00	$80.00
Variable O&M	$/MWh	$8.75	$24.00	—		—		—	
Heat Rate	Btu/kWh	—		—		—		—	
Capacity Factor	%	90%	80%	55%	30%	45%	30%	55%	45%
Fuel Price	$/MMBTU	—		—		—		—	
Construction Time	Months	36		12		12		12	
Facility Life	Years	25		20		20		20	
Levelized Cost of Energy	$/MWh	$61	$102	$24	$75	$42	$114	$72	$140

Source: *Lazard and Roland Berger estimates and publicly available information.*
(1) Given the limited data set available for new-build geothermal projects, the LCOE presented herein represents Lazard's LCOE v15.0 results adjusted for inflation.
(2) Includes capitalized financing costs during construction for generation types with over 12 months of construction time.

Levelized Cost of Energy—Key Assumptions (cont'd)

	Units	Gas Peaking			Nuclear (New Build) [1]			Coal (New Build) [2]			Gas Combined Cycle (New Build)		
		Low Case		High Case	Low Case		High Case	Low Case		High Case	Low Case		High Case
Net Facility Output	MW	240	–	50		2,200			600			550	
Total Capital Costs [3]	$/kW	$700	–	$1,150	$8,475	–	$13,925	$3,200	–	$6,775	$650	–	$1,300
Fixed O&M	$/kW-yr	$7.00	–	$17.00	$131.50	–	$152.75	$39.50	–	$91.25	$10.00	–	$17.00
Variable O&M	$/MWh		—		$4.25	–	$5.00	$3.00	–	$5.50	$2.75	–	$5.00
Heat Rate	Btu/kWh		—			10,450		8,750	–	12,000	6,150	–	6,900
Capacity Factor	%	15%	–	10%	92%	–	89%	85%	–	65%	90%	–	30%
Fuel Price	$/MMBTU		—			$0.85			$1.47			$3.45	
Construction Time	Months		12			69		60	–	66		24	
Facility Life	Years		20			40			40			20	
Levelized Cost of Energy	$/MWh	$115	–	$221	$141	–	$221	$68	–	$166	$39	–	$101

Source: Lazard and Roland Berger estimates and publicly available information.

(1) Given the limited public and/or observable data set available for new-build nuclear projects and the emerging range of new nuclear generation strategies, the LCOE presented herein represents Lazard's LCOE v15.0 results adjusted for inflation (results are based on then-estimated costs of the Vogtle Plant and are U.S.-focused).

(2) High end incorporates 90% CCS. Does not include cost of transportation and storage. Given the limited public and/or observable data set available for new-build coal projects, the LCOE presented herein represents Lazard's LCOE v15.0 results adjusted for inflation.

(3) Includes capitalized financing costs during construction for generation types with over 12 months of construction time.

Levelized Cost of Energy—Key Assumptions (cont'd)

	Units	Nuclear (Operating) Low Case		Nuclear (Operating) High Case	Coal (Operating) Low Case		Coal (Operating) High Case	Gas Combined Cycle (Operating) Low Case		Gas Combined Cycle (Operating) High Case
Net Facility Output	MW	2,200			600			550		
Total Capital Costs[(1)]	$/kW	$0.00			$0.00			$0.00		
Fixed O&M	$/kW-yr	$97.25	–	$120.00	$18.50	–	$31.00	$9.25	–	$14.00
Variable O&M	$/MWh	$3.05	–	$3.55	$2.75	–	$5.50	$1.00	–	$2.00
Heat Rate	Btu/kWh	10,400			10,075	–	11,075	6,925	–	7,450
Capacity Factor	%	95%	–	90%	65%	–	35%	70%	–	45%
Fuel Price	$/MMBTU	$0.79			$1.89	–	$4.33	$6.00	–	$7.69
Construction Time	Months	69			60	–	66	24		
Facility Life	Years	40			40			20		
Levelized Cost of Energy	$/MWh	$29	–	$34	$29	–	$74	$51	–	$73

Source: Lazard and Roland Berger estimates and publicly available information.
(1) Includes capitalized financing costs during construction for generation types with over 12 months of construction time.

C LCOS v8.0

Levelized Cost of Storage Comparison—Methodology

Lazard's LCOS analysis consists of creating a power plant model representing an illustrative project for each relevant technology and solving for the $/MWh value that results in a levered IRR equal to the assumed cost of equity (see subsequent "Key Assumptions" pages for detailed assumptions by technology)

Subsidized Utility-Scale (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	109	106	103	100	110	102
Total Generation ('000 MWh)[2]	(B)*		63	63	63	63	63	63
Levelized Storage Cost ($/MWh)	***(C)***		***$178***	***$178***	***$178***	***$178***	***$178***	***$178***
Total Revenues	**(B) x (C) = (D)***		**$11.2**	**$11.2**	**$11.2**	**$11.2**	**$11.2**	**$11.2**
Total Charging Cost[3]	(E)		(4.4)	(4.5)	(4.6)	(4.7)	(4.8)	(6.3)
Total O&M, Warranty, & Augmentation[4]	(F)*		(0.3)	(0.3)	(0.6)	(0.6)	(4.3)	(0.8)
Total Operating Costs	**(E) + (F) = (G)**		($4.7)	($4.8)	($5.2)	($5.3)	($9.1)	($7.1)
EBITDA	**(D) - (G) = (H)**		**$6.5**	**$6.4**	**$5.9**	**$5.8**	**$2.1**	**$4.1**
Debt Outstanding - Beginning of Period	(I)		$11.7	$11.4	$11.2	$10.9	$10.5	$1.1
Debt - Interest Expense	(J)		(0.9)	(0.9)	(0.9)	(0.9)	(0.8)	(0.1)
Debt - Principal Payment	(K)		(0.3)	(0.3)	(0.3)	(0.3)	(0.3)	(1.1)
Levelized Debt Service	(J) + (K) = (L)		(1.2)	(1.2)	(1.2)	(1.2)	(1.2)	(1.2)
EBITDA	**(H)**		$6.5	$6.4	$5.9	$5.8	$2.1	$4.1
Depreciation (5-yr MACRS)	(M)		(9.9)	(15.9)	(9.5)	(5.7)	(5.7)	0.0
Interest Expense	(J)		(0.9)	2.8	0.0	(0.0)	0.0	0.0
Taxable Income	**(H) + (M) + (J) = (N)**		**($4.4)**	**($6.6)**	**($3.6)**	**$0.1**	**($3.6)**	**$4.1**
Tax Benefit (Liability)	**(N) x (Tax Rate) = (O)**		**$0.9**	**$1.4**	**$0.8**	**($0.0)**	**$0.8**	**($0.9)**
Federal Investment Tax Credit (ITC)	**(P)**		**$17.5**	**$0.0**	**$0.0**	**$0.0**	**$0.0**	**$0.0**
Capital Expenditures		**($46.7)**	**($11.7)**	**$0.0**	**$0.0**	**$0.0**	**$0.0**	**$0.0**
After-Tax Net Equity Cash Flow	**(H) + (L) + (O) + (P) = (Q)**	**($46.7)**[7]	**$23.7**	**$6.6**	**$5.5**	**$4.6**	**$1.7**	**$2.1**

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
Charging Cost ($/kWh)	$0.064
Fixed O&M Cost ($/kWh)	$1.30
Fixed O&M Escalator (%)	2.5%
Charging Cost Escalator (%)	1.87%
Efficiency (%)	91%
Capital Structure	
Debt	20.0%
Cost of Debt	8.0%
Equity	80.0%
Cost of Equity	12.0%
Taxes	
Combined Tax Rate	21.0%
Contract Term / Project Life (years)	20
MACRS Depreciation Schedule	5 Years
Federal ITC - BESS	30%
Capex	
Total Initial Installed Cost ($/kWh)[6]	$292
Extended Warranty (% of Capital Cost)	0.7%
Extended Warranty Start Year	3
Total Capex ($mm)	$58

Use-case specific

Global assumptions

Source: *Lazard and Roland Berger estimates and publicly available information.*
Note: Subsidized Utility-Scale (100 MW / 200 MWh)—Low LCOS case presented for illustrative purposes only.
* 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 ($1.30/kWh, plus any relevant Solar PV or Wind O&M, escalating annually at 2.5%), augmentation costs (incurred in years needed to maintain usable energy at original storage module cost) and warranty costs (0.7% 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 $35/kW, Module cost of $188/kWh, Balance-of-System cost of $30/kWh and EPC cost of $30/kWh.
(7) Reflects initial cash outflow from equity sponsor.

Levelized Cost of Storage—Key Assumptions

	Units	Utility-Scale (Standalone) (100 MW / 100 MWh)	Utility-Scale (Standalone) (100 MW / 200 MWh)	Utility-Scale (Standalone) (100 MW / 400 MWh)	Utility-Scale (PV + Storage) (50 MW / 200 MWh)	Utility-Scale (Wind + Storage) (50 MW / 200 MWh)	C&I (Standalone) (1 MW / 2 MWh)	C&I (PV + Storage) (0.5 MW / 2 MWh)	Residential (Standalone) (0.006 MW / 0.025 MWh)	Residential (PV + Storage) (0.006 MW / 0.025 MWh)
Power Rating	MW	100	100	100	50	50	1	0.5	0.006	0.006
Duration	Hours	1.0	2.0	4.0	4.0	4.0	2.0	4.0	4.2	4.2
Usable Energy	MWh	100	200	400	200	200	2	2	0.025	0.025
90% Depth of Discharge Cycles/Day	#	1	1	1	1	1	1	1	1	1
Operating Days/Year	#	350	350	350	350	350	350	350	350	350
Solar / Wind Capacity	MW	0.00	0.00	0.00	100	100	0.00	1.00	0.000	0.010
Annual Solar / Wind Generation	MWh	0	0	0	197,000	372,000	0	1,752	0	15
Project Life	Years	20	20	20	20	20	20	20	20	20
Annual Storage Output	MWh	31,500	63,000	126,000	63,000	63,000	630	630	8	8
Lifetime Storage Output	MWh	630,000	1,260,000	2,520,000	1,260,000	1,260,000	12,600	12,600	158	158
Initial Capital Cost—DC	$/kWh	$280 – $359	$223 – $315	$225 – $304	$200 – $279	$200 – $279	$429 – $469	$326 – $362	$1,261 – $1,429	$1,150 – $1,286
Initial Capital Cost—AC	$/kW	$35 – $80	$35 – $80	$35 – $80	$20 – $60	$20 – $60	$50 – $80	$50 – $80	$101 – $114	$92 – $103
EPC Costs	$/kWh	$30 – $70	$30 – $70	$30 – $70	$30 – $70	$30 – $70	$59 – $106	$47 – $89	$0 – $0	$0 – $0
Solar / Wind Capital Cost	$/kW	$0 – $0	$0 – $0	$0 – $0	$1,050 – $1,050	$1,350 – $1,350	$0 – $0	$2,025 – $2,025	$0 – $0	$3,175 – $3,175
Total Initial Installed Cost	$	$35 – $51	$54 – $85	$106 – $158	$47 – $73	$47 – $73	$1 – $1	$1 – $1	$0 – $0	$0 – $0
Storage O&M	$/kWh	$1.7 - $9.7	$1.3 - $7.7	$1.2 - $6.7	$1.2 - $6.7	$1.2 - $6.7	$2.5 - $11.2	$1.9 - $8.8	$0.0 - $0.0	$0.0 - $0.0
Extended Warranty Start	Year	3	3	3	3	3	3	3	3	3
Warranty Expense % of Capital Costs	%	0.50% - 0.80%	0.50% - 0.80%	0.50% - 0.80%	0.50% - 0.80%	0.50% - 0.80%	0.50% - 0.80%	0.50% - 0.80%	0.00% - 0.00%	0.00% - 0.00%
Investment Tax Credit (Solar)	%	0%	0%	0%	30% - 40%	0%	0%	30% - 40%	0%	30% - 40%
Investment Tax Credit (Storage)	%	30% - 40%	30% - 40%	30% - 40%	30% - 40%	30% - 40%	30% - 40%	30% - 40%	30% - 40%	30% - 40%
Production Tax Credit	$/MWh	$0	$0	$0	$0	$26 - $29	$0	$0	$0	$0
Charging Cost	$/MWh	$61	$64	$59	$0	$0	$117	$0	$325	$0
Charging Cost Escalator	%	1.87%	1.87%	1.87%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Efficiency of Storage Technology	%	91% – 88%	91% – 88%	91% – 88%	91% – 88%	91% – 88%	91% – 88%	91% – 88%	95% – 90%	95% – 90%
Unsubsidized LCOS	$/MWh	$249 - $323	$215 - $285	$200 - $257	$110 - $131	$69 - $79	$407 - $448	$225 - $241	$1,215 - $1,348	$663 - $730

x

Source: *Lazard and Roland Berger estimates and publicly available information.*
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). All cases were modeled using 90% depth of discharge. Wholesale charging costs reflect weighted average hourly wholesale energy prices across a representative charging profile of a standalone storage asset participating in wholesale revenue streams. Escalation is derived from the EIA's "AEO 2022 Energy Source–Electric Price Forecast (20-year CAGR)". Storage systems paired with Solar PV or Wind do not charge from the grid.

D LCOH v3.0

Levelized Cost of Hydrogen Comparison—Methodology

($ in millions, unless otherwise noted)

Lazard's LCOH analysis consists of creating a model representing an illustrative project for each relevant technology and solving for the $/kg value that results in a levered IRR equal to the assumed cost of equity (see subsequent "Key Assumptions" pages for detailed assumptions by technology)

Unsubsidized Green PEM—High Case Sample Illustrative Calculations

Year[1]			*1*	*2*	*3*	*4*	*5*	*25*
Electrolyzer size (MW)	(A)		20	20	20	20	20	20
Electrolyzer input capacity factor (%)	(B)		55%	55%	55%	55%	55%	55%
Total electric demand (MWh)[2]	(A) x (B) = (C)*		96,360	96,360	96,360	96,360	96,360	96,360
Electric consumption of H2 (kWh/kg)[3]	(D)		61.87	61.87	61.87	61.87	61.87	61.87
Total H2 output ('000 kg)	(C) / (D) = (E)		1,558	1,558	1,558	1,558	1,558	1,558
Levelized Cost of Hydrogen ($/kg)	***(F)***		***$7.37***	***$7.37***	***$7.37***	***$7.37***	***$7.37***	***$7.37***
Total Revenues	**(E) x (F) = (G)***		**$11.47**	**$11.47**	**$11.47**	**$11.47**	**$11.47**	**$11.47**
Warranty / insurance	(H)		--	--	($0.5)	($0.5)	($0.5)	($0.6)
Total O&M	(I)*		(5.3)	(5.4)	(5.4)	(5.4)	(5.4)	(5.8)
Total Operating Costs	**(H) + (I) = (J)**		**($5.3)**	**($5.4)**	**($5.8)**	**($5.8)**	**($5.9)**	($6.3)
EBITDA	**(G) - (J) = (K)**		**$6.1**	**$6.1**	**$5.6**	**$5.6**	**$5.6**	**$5.1**
Debt Outstanding - Beginning of Period	(L)		$18.1	$17.9	$17.6	$17.3	$17.0	$1.6
Debt - Interest Expense	(M)		($1.4)	($1.4)	($1.4)	($1.4)	($1.4)	($0.1)
Debt - Principal Payment	(N)		($0.2)	($0.3)	($0.3)	($0.3)	($0.3)	($1.6)
Levelized Debt Service	(M) + (N) = (O)		($1.7)	($1.7)	($1.7)	($1.7)	($1.7)	($1.7)
EBITDA	**(K)**		$6.1	$6.1	$5.6	$5.6	$5.6	$5.1
Depreciation (MACRS)	(P)		(6.5)	(11.1)	(7.9)	(5.7)	(4.0)	0.0
Interest Expense	(M)		(1.4)	(1.4)	(1.4)	(1.4)	(1.4)	(0.1)
Taxable Income	**(K) + (P) + (M) = (Q)**		**($1.8)**	**($6.4)**	**($3.7)**	**($1.4)**	**$0.2**	**$5.0**
Tax Benefit (Liability)	**(Q) x (tax rate) = (R)**		**$0.4**	**$1.3**	**$0.8**	**$0.3**	**($0.0)**	**$2.9**
Capital Expenditures		**($27)**[4]	**($18.1)**	**$0.0**	**$0.0**	**$0.0**	**$0.0**	**$0.0**
After-Tax Net Equity Cash Flow	**(K) + (O) + (R) = (S)**		**$4.8**	**$5.8**	**$4.7**	**$4.2**	**$3.9**	**$6.3**

IRR For Equity Investors	**12.0%**

Key Assumptions[5]	
Electrolyzer size (MW)	20.00
Electrolyzer input capacity factor (%)	55%
Lower heating value of hydrogen (kWh/kgH2)	33
Electrolyzer efficiency (%)	58.0%
Levelized penalty for efficiency degradation (kWh/kg)	4.4
Electric consumption of H2 (kWh/kg)	61.87
Warranty / insurance	1.0%
Total O&M	5.34
O&M escalation	2.00%
Capital Structure	
Debt	40.0%
Cost of Debt	8.0%
Equity	60.0%
Cost of Equity	12.0%
Taxes and Tax Incentives:	
Combined Tax Rate	21%
Economic Life (years)[6]	25
MACRS Depreciation (Year Schedule)	7-Year MACRS
Capex	
EPC Costs ($/kW)	$2,265
Additional Owner's Costs ($/kW)	$0
Transmission Costs ($/kW)	$0
Total Capital Costs ($/kW)	$2,265
Total Capex ($mm)	$45

Technology-dependent

Levelized

Source: *Lazard and Roland Berger estimates and publicly available information.*
Note: Unsubsidized Green PEM—High LCOH case presented for illustrative purposes only.
* Denotes unit conversion.
(1) Assumes half-year convention for discounting purposes.
(2) Total Electric Demand reflects (Electrolyzer Size) x (Electrolyzer Capacity Factor) x (8,760 hours/year).
(3) Electric Consumption reflects (Heating Value of Hydrogen) x (Electrolyzer Efficiency) + (Levelized Degradation).
(4) Reflects initial cash outflow from equity investors.
(5) Reflects a "key" subset of all assumptions for methodology illustration purposes only. Does not reflect all assumptions.
(6) Economic life sets debt amortization schedule.

Levelized Cost of Hydrogen—Key Assumptions

		Green Hydrogen						Pink Hydrogen					
		PEM			Alkaline			PEM			Alkaline		
	Units	**Low Case**		**High Case**	**Low Case**		**High Case**	**Low Case**		**High Case**	**Low Case**		**High Case**
Capacity	MW	100	–	20	100	–	20	100	–	20	100	–	20
Total Capex	$/kW	$943	–	$2,265	$740	–	$1,984	$1,013	–	$2,335	$810	–	$2,054
Electrolyzer Stack Capex	$/kW	$341	–	$1,052	$203	–	$652	$341	–	$1,052	$203	–	$652
Plant Lifetime	Years		25			25			25			25	
Stack Lifetime	Hours		60,000			67,500			60,000			67,500	
Heating Value	kWh/kg H2		33			33			33			33	
Electrolyzer Utilization	%		90%			90%			90%			90%	
Electrolyzer Capacity Factor	%		55%			55%			95%			95%	
Electrolyzer Efficiency	% LHV		58%			67%			58%			67%	
Operating Costs:													
Annual H2 Produced	MT	7,788	–	1,558	8,902	–	1,780	12,744	–	2,549	14,568	–	2,914
Process Water Costs	$/kg H2		$0.005			$0.005			$0.005			$0.005	
Annual Energy Consumption	MWh	481,800	–	96,360	481,800	–	96,360	788,400	–	157,680	788,400	–	157,680
Net Electricity Cost (Unsubsidized)	$/MWh		$48.00			$48.00			$35.00			$35.00	
Net Electricity Cost (subsidized)	$/MWh		$30.56			$30.56			$30.31			$30.31	
Warranty & Insurance (% of Capex)	%		1.0%			1.0%			1.0%			1.0%	
Warranty & Insurance Escalation	%		1.0%			1.0%			1.0%			1.0%	
O&M (% of Capex)	%		1.50%			1.50%			1.50%			1.50%	
Annual Inflation	%		2.00%			2.00%			2.00%			2.00%	
Capital Structure:													
Debt	%		40.0%			40.0%			40.0%			40.0%	
Cost of Debt	%		8.0%			8.0%			8.0%			8.0%	
Equity	%		60.0%			60.0%			60.0%			60.0%	
Cost of Equity	%		12.0%			12.0%			12.0%			12.0%	
Tax Rate	%		21.0%			21.0%			21.0%			21.0%	
WACC	%		9.7%			9.7%			9.7%			9.7%	
Unsubsidized Levelized Cost of Hydrogen	**$/kg**	**$4.77**		**$7.37**	**$3.79**		**$5.78**	**$3.47**		**$5.29**	**$2.75**		**$4.08**
Subsidized Levelized Cost of Hydrogen	**$/kg**	**$1.68**		**$4.28**	**$0.83**		**$2.83**	**$1.16**		**$2.99**	**$0.48**		**$1.81**
Memo: Unsubsidized Natural Gas Equivalent Cost	***$/MMBTU***	***$41.90***		***$64.65***	***$33.30***		***$50.70***	***$30.40***		***$46.45***	***$24.15***		***$35.80***
Memo: Subsidized Natural Gas Equivalent Cost	***$/MMBTU***	***$14.80***		***$37.55***	***$7.30***		***$24.80***	***$10.20***		***$26.25***	***$4.25***		***$15.90***

Source: *Lazard and Roland Berger estimates and publicly available information.*

Levelized Cost of Energy—Gas Peaking Plant with 25% Hydrogen Blend Key Assumptions

		Green Hydrogen						Pink Hydrogen					
		PEM			Alkaline			PEM			Alkaline		
	Units	Low Case		High Case	Low Case		High Case	Low Case		High Case	Low Case		High Case
Capacity	MW		20			20			20			20	
Total Capex	$/kW	$1,412	–	$2,265	$1,230	–	$1,984	$1,482	–	$2,335	$1,300	–	$2,054
Electrolyzer Stack Capex	$/kW	$479	–	$1,052	$186	–	$652	$479	–	$1,052	$186	–	$652
Plant Lifetime	Years		25			25			25			25	
Stack Lifetime	Hours		60,000			67,500			60,000			67,500	
Heating Value	kWh/kg H2		33			33			33			33	
Electrolyzer Utilization	%		90%			90%			90%			90%	
Electrolyzer Capacity Factor	%		55%			55%			95%			95%	
Electrolyzer Efficiency	% LHV		58%			67%			58%			67%	
Operating Costs:													
Annual H2 Produced	MT		1,558			1,780			2,549			2,914	
Process Water Costs	$/kg H2		$0.005			$0.005			$0.005			$0.005	
Annual Energy Consumption	MWh		96,360			96,360			157,680			157,680	
Net Electricity Cost (Unsubsidized)	$/MWh		$48.00			$48.00			$35.00			$35.00	
Net Electricity Cost (subsidized)	$/MWh		$30.56			$30.56			$30.31			$30.31	
Warranty & Insurance (% of Capex)	%		1.0%			1.0%			1.0%			1.0%	
Warranty & Insurance Escalation	%		1.0%			1.0%			1.0%			1.0%	
O&M (% of Capex)	%		1.50%			1.50%			1.50%			1.50%	
Annual Inflation	%		2.00%			2.00%			2.00%			2.00%	
Capital Structure:													
Debt	%		40.0%			40.0%			40.0%			40.0%	
Cost of Debt	%		8.0%			8.0%			8.0%			8.0%	
Equity	%		60.0%			60.0%			60.0%			60.0%	
Cost of Equity	%		12.0%			12.0%			12.0%			12.0%	
Tax Rate	%		21.0%			21.0%			21.0%			21.0%	
WACC	%		9.7%			9.7%			9.7%			9.7%	
Unsubsidized Levelized Cost of Hydrogen	**$/kg**	**$5.65**		**$7.37**	**$4.53**		**$5.78**	**$4.05**		**$5.29**	**$3.20**		**$4.08**
Subsidized Levelized Cost of Hydrogen	**$/kg**	**$2.55**		**$4.28**	**$1.57**		**$2.83**	**$1.74**		**$2.99**	**$0.93**		**$1.81**
Natural gas price	$/mmbtu		$3.45			$3.45			$3.45			$3.45	
Peaker LCOE at 0% H2 blend by vol. (unsubsidized)	$/MWh		$173.00			$173.00			$173.00			$173.00	
Peaker LCOE at 25% H2 blend by vol. (unsubsidized)	**$/MWh**	**$220**	–	**$235**	**$210**	–	**$221**	**$206**	–	**$217**	**$198**	–	**$206**
Peaker LCOE at 25% H2 blend by vol. (subsidized)	**$/MWh**	**$193**	–	**$208**	**$184**	–	**$195**	**$185**	–	**$196**	**$178**	–	**$186**
Memo: Unsubsidized Natural Gas Equivalent Cost	***$/MMBTU***	***$49.55***		***$64.65***	***$39.75***		***$50.70***	***$35.50***		***$46.45***	***$28.05***		***$35.80***
Memo: Subsidized Natural Gas Equivalent Cost	***$/MMBTU***	***$22.40***		***$37.55***	***$13.75***		***$24.80***	***$15.30***		***$26.25***	***$8.15***		***$15.90***

Source: *Lazard and Roland Berger estimates and publicly available information.*