U.S. House Committee on Energy and Commerce
Full Committee Markup of 13 Bills
Documents for the Record
June 25, 2025

1. A letter from the National Mining Association, addressed to Chairman Guthrie and Ranking Member Pallone, submitted by the Majority.
2. A letter from the National Hydropower Association, Inc., addressed to Chairman Latta and Ranking Member Pallone, submitted by Rep. Griffith.
3. A letter from Americans for Prosperity, addressed to Chairman Guthrie and Ranking Member Pallone, submitted by Rep. Griffith.
4. An article from Utility Dive entitled, “NERC Upgrades MISO reliability risk after ‘data mismatch’ discovered,” filed by Rep. DeGette.
5. A letter from the Department of Energy, addressed to Chairman Guthrie, submitted by Ranking Member Pallone.
6. A letter from the Industrial Energy Consumers of America, addressed to Chairman Guthrie and Ranking Member Pallone, submitted by Rep. Castor.
7. A report from Lazard LCOE entitled, “Lazard’s Levelized Cost of Energy Analysis—Version 18.0,” submitted by Rep. Ruiz.
8. An article from Reuters entitled, “Renewable Energy Remains Cheapest Power Builds as New Gas Plants Get Pricier,” submitted by Rep. Ruiz.
9. An article from E&E News entitled, “Pipeline Enforcement Plunges in Trump’s First Months,” submitted by Rep. Menendez.

Rich Nolan
President & CEO

June 24, 2025

The Honorable Brett Guthrie
Chairman
Committee on Energy and Commerce
U.S. House of Representatives
Washington, D.C. 20515

The Honorable Frank Pallone
Ranking Member
Committee on Energy and Commerce
U.S. House of Representatives
Washington, D.C. 20515

Dear Chairman Guthrie, Ranking Member Pallone and Members of the committee:

The National Mining Association (NMA) strongly supports the committee's markup of legislation focused on protecting the reliability, affordability, and resilience of America's electric grid. We thank Energy Subcommittee Chairman Bob Latta (R-Ohio) and members of the Committee for their leadership and urge you to report these bills favorably to the full House.

The NMA is the only national trade organization that serves as the voice of the U.S. mining industry and the hundreds of thousands of American workers it employs before Congress, the federal agencies, the judiciary, and the media, advocating for public policies that will help America fully and responsibly utilize its vast natural resources. We work to ensure America has secure and reliable supply chains, abundant and affordable energy, and the American-sourced materials necessary for U.S. manufacturing, national security, and economic security, all delivered under world-leading environmental, safety, and labor standards. The NMA has a membership of nearly 300 companies and organizations involved in every aspect of mining, from producers and equipment manufacturers to service providers.

These legislative proposals offer urgently needed solutions to the worsening reliability crisis facing our bulk power system. As America enters a new era of electrification and explosive demand growth—driven in large part by AI and data center expansion—the nation cannot afford to lose more dependable, dispatchable generation. Recent projections show grid operators like PJM and the Southwest Power Pool forecasting demand increases of 30–75% within the next decade. Yet while demand soars, poor planning decisions and politically driven retirements of fuel-secure generation continue to weaken the grid. These bills take meaningful steps to reverse that trajectory, protect on-demand power sources like coal, and ensure Americans have access to affordable, always-available electricity when they need it most. Specifically, the NMA urges passage of the following bills:

- H.R. 3616, the Reliable Power Act, introduced by Rep. Troy Balderson (R-Ohio), provides a commonsense safeguard against federal regulations that could compromise electric grid reliability. The bill requires the Federal Energy

Regulatory Commission (FERC) to review proposed regulations from federal agencies when the North American Electric Reliability Corporation (NERC) issues a formal finding that the grid is at risk of generation inadequacy. Agencies would be prohibited from finalizing such regulations unless FERC determines the action would not significantly impair the grid's ability to supply sufficient electricity. As electricity demand rises rapidly, this legislation ensures federal policy does not worsen reliability risks by sidelining dependable, fuel-secure generation sources.

- H.R. 3632, the Power Plant Reliability Act, introduced by Rep. Morgan Griffith (R-Va.), which gives FERC the authority to intervene in premature generation retirements that threaten grid stability. It also requires owners to give five years' notice before closing plants—providing the time and transparency grid operators need to plan for reliable replacement capacity.

- H.R. 3015, the National Coal Council Reestablishment Act, introduced by Rep. Michael Rulli (R-Ohio), formally codifies in law the National Coal Council, which was reestablished by presidential executive order on April 8, 2025. This bill ensures that coal—a dependable, fuel-secure energy source—maintains an institutional voice in Department of Energy policymaking through a permanent advisory body.

- H.R. 3628, the State Planning for Reliability and Affordability Act, introduced by Rep. Gabe Evans (R-Colo.), which requires states to evaluate whether their energy resource plans can maintain an adequate electricity supply over a 10-year outlook. The bill encourages states to account for dependable, fuel-secure resources that can operate continuously during normal fluctuations in weather and demand. Poor planning decisions—not the weather—are increasingly turning routine conditions into grid emergencies, putting American lives at risk and exposing the consequences of sidelining dispatchable generation.

- H.R. 3157, the State Energy Accountability Act, introduced by Rep. Nick Langworthy (R-N.Y.), would require states pursuing renewable energy mandates to disclose how these policies impact electricity rates, reliability, and reliance on out-of-state generation. States chasing 100% renewable portfolios often promote low-cost energy without acknowledging that inverter-based resources—like wind and solar—only produce power when subject to weather conditions. These conditions rarely align with periods of peak electricity demand, forcing grid operators to rely on higher-cost generation from other states to maintain system balance. This mismatch drives up electricity prices and hides the true cost of relying on weather-dependent resources. Ratepayers deserve transparency about how these policies affect both their bills and the grid's ability to deliver dependable electricity when it is needed most.

Together, these bills represent a decisive course correction—prioritizing reliability, transparency, and realism in federal and state energy policy. As FERC commissioners, grid operators, and energy experts have warned, the U.S. is rapidly heading toward a reliability crisis. Demand is rising at an unprecedented pace, while regulatory policies continue to force essential generation offline. This package aligns policy with reality: dependable, dispatchable power—especially coal—is indispensable to keeping the lights on.

We thank Chairman Guthrie, Subcommittee Chairman Latta, and the sponsors of these bills—Reps. Balderson, Griffith, Rulli, Evans, and Langworthy—for their leadership. We urge the full committee to support this critical legislative package to ensure that Americans have access to affordable, dependable power and that federal energy policy meets this challenge.

Sincerely,

Rich Nolan

The National Hydropower Association, Inc.
200 Massachusetts Ave NW, Suite 320, Washington, DC 20001 • 202.805.5057 • www.hydro.org

June 24, 2025

The Honorable Brett Guthrie
Chairman
Energy and Commerce Committee
U.S. House of Representatives
2125 Rayburn House Office Building
Washington, DC 20515

The Honorable Frank Pallone, Jr.
Ranking Member
Energy and Commerce Committee
U.S. House of Representatives
2322A Rayburn House Office Building
Washington, DC 20515

Dear Chairman Guthrie and Ranking Member Pallone:

On behalf of the National Hydropower Association, I am writing to express strong support for H.R. 3632, the *Power Plant Reliability Act*. This legislation offers critical safeguards for the reliability of the nation's power grid and presents an important opportunity for the continued success and stability of the hydropower industry.

Hydropower is America's original renewable resource and continues to serve as a backbone of reliable, carbon-free baseload electricity. As aging generating assets across the country face economic, environmental, and regulatory pressures, we commend your leadership in introducing legislation that recognizes the strategic importance of retaining dispatchable resources like hydropower during grid transition periods.

By allowing Regional Transmission Organizations (RTOs) and state utility commissions to petition the Federal Energy Regulatory Commission (FERC) to keep essential generating facilities online during times of reliability risk, the *Power Plant Reliability Act* ensures that necessary infrastructure—including hydropower—is not prematurely lost. The bill also provides a process for compensating asset owners required to continue operations and makes clear determinations regarding cost allocation—critical for small, publicly owned utilities and independent hydropower operators.

Importantly, the bill's advance notice requirements for planned retirements of generating units offer much-needed transparency and planning certainty. This is especially relevant for grid operators and communities dependent on legacy generation, as well as for hydropower operators who must coordinate complex water management responsibilities tied to electric generation.

As hydropower continues to support energy dominance, grid stability, national security and economic development, we appreciate your commitment to advancing policies that preserve this vital resource. The *Power Plant Reliability Act* is a pragmatic solution to a growing reliability challenge, and we strongly encourage its swift passage.

Thank you for your continued support of reliable, American-made hydropower.

Sincerely,

Matthew Allen

Matthew Allen
Director of Legislative Affairs
National Hydropower Association

AMERICANS for PROSPERITY

June 25th, 2025

The Honorable Brett Guthrie
Chairman
Committee on Energy & Commerce

The Honorable Frank Pallone, Jr.
Ranking Member
Committee on Energy & Commerce

Dear Chairman Guthrie & Ranking Member Pallone,

On behalf of our activists across the country, we urge you to support **H.R. 3632, the Power Plant Reliability Act of 2025,** introduced by **Representative Morgan Griffith.**

As the country experiences the heat of summer, we are pleased to see opportunities in this legislation for the Federal Energy Regulatory Commission (FERC) to adjust the regulatory scope of their oversight capacity in providing operators the ability to meet electric demand during peak loads. Additionally, this legislation provides critical abilities to FERC to delay the retirement of baseload generation units to maintain adequate electric service and meet peak load service during high demand periods.

According to the Energy Information Agency, electricity generators in the United States plan to retire 12.3 gigawatts of capacity in 2025, a "65% increase in retirements compared with 2024." Additionally, electric generators are planning to retire 8.1 gigawatts of coal-fired capacity. Included in that assessment is one 1,800-megawatt generation coal-fired unit in Utah and another coal-fired unit in Maryland that produces 1,273 megawatts. Gas-fired units will see a retirement of 2.6 gigawatts of capacity this year and petroleum-fired units will see a retirement of 1.6 gigawatts in the United States.

While certain retiring generation units are being replaced with other baseload generation technologies, the demand for electricity is only growing, which creates problems for meeting consumer and commercial demand with the retirement of baseload generation. Always-available sources of generation (or baseload) are critical in providing reliable service to the American people and maintaining the 60 Hz frequency that our power grid operates on.

H.R. 3632 amends the Federal Power Act to ensure that certain retirements do not negatively impact grid reliability and service to consumers. Additionally, it requires power operators and owners to provide advance notice of the retirement of generating units. H.R. 3632 will also provide FERC with the ability to compel continued operation of certain generation units to provide adequate electric service while limiting FERC's ability to force operators to expand generation facilities for planned retirement. This legislation comes at a critical time for the American people especially after the last administration pushed for the retirement of many reliable power generation systems.

As the Committee on Energy & Commerce considers H.R. 3632 during the full Committee markup, we urge you to think of the most vulnerable members of society that depend upon the decision made today. It is urgent that the Committee reverse the green energy policies of the previous administration and provide pathways for reliable baseload generation units to survive and continue to provide much needed energy to our electric grid. For these reasons, we ask that you vote “YES” on H.R. 3632.

Sincerely,

Brent Gardner
Chief Government Affairs Officer

UTILITY DIVE

DIVE BRIEF

NERC upgrades MISO reliability risk after 'data mismatch' discovered

The Midcontinent Independent System Operator faces an elevated risk of energy shortfalls over the next few years but had been classified by NERC as facing a more dire "high risk."

Published June 18, 2025

Robert Walton
Senior Reporter

The Midcontinent Independent System Operator control room. The grid operator said it is exploring the cause for mismatched data submitted to the North American Electric Reliability Corp. Permission granted by Midcontinent Independent System Operator

After finding a "data mismatch," the North American Electric Reliability Corp. on Tuesday said the Midcontinent Independent System Operator's reliability risk wasn't as bad as reported by the grid watchdog in a December assessment.

"When reanalyzed with the corrected data, the MISO footprint was reclassified as an 'elevated risk' over the next few years, shifting to 'high risk' in the 2028–2031 timeframe, depending on new resource additions/retirements," the reliablity watchdog said in a statement.

Elevated risk means an area meets resource adequacy criteria but under extreme weather conditions remains likely to experience a shortfall in reserves, NERC said.

In December NERC published its Long-Term Reliability Assessment, concluding that more than half of North America faces a risk of energy shortfalls in the next five to 10 years. While many areas were classified at an “elevated” risk, the report warned MISO faced a “high risk” beginning this year, with energy shortfalls in some areas possible during normal peak conditions.

But at a technical conference on resource adequacy challenges, held earlier this month by the Federal Energy Regulatory Commission, MISO’s market monitor cast doubt on those conclusions.

“I’d love to work with NERC to figure out where they got their numbers from, because I don’t think they’re accurate,” David Patton, president of Potomac Economics, said at the June 5 conference.

According to Patton, NERC understated MISO’s capacity for demand response, behind-the-meter generation and firm capacity imports by more than 8 GW. And it considered possible power plant retirements that have not occurred, he said.

“Following an in-depth review, NERC found that MISO submitted mismatched data, which overstated the near-term energy shortfall risk,” the reliability organization said.

The grid operator is exploring the cause for the mismatched data, it said. “We are in close contact with NERC and will provide an update as we learn more,” MISO said in a statement.

NERC said that “while this data mismatch went unnoticed by MISO and the Midwest Reliability Organization that initially collects and vets the data, NERC is ultimately responsible for ensuring the accuracy of its independent reliability assessments and is working to improve its review process. … Going forward, NERC, MRO and MISO are all committed to improving the data validation process to ensure accuracy.”

A corrected version of the 2024 LTRA will be posted soon, NERC said. The data error did not have an impact on the 2025 Summer Reliability Assessment, released in May, NERC added.

The MISO region has less supply capacity than it did last summer, according to the May report. MISO officials expect peak demand may reach nearly 123 GW, but say there is about 138 GW of regularly available generation expected across the operating footprint.

Market monitor Patton said he is glad to see NERC will be reviewing its processes for future reports, but he has broader questions about the assessment.

“Regarding the reclassification, I question NERC’s benchmark,” Patton said in an email. “The question is: MISO’s risk is ‘elevated’ compared to what? It is exceeding its 1-in-10 reliability criteria and has among the largest interface capability with neighboring areas in the country that provides flexibility during extreme events. I would classify it as moderate to low risk.”

“The risk that an RTO may be short of reserves during extreme events does not indicate an elevated or high risk,” Patton added. “This is expected in well-functioning competitive electricity markets.”

EDITOR’S NOTE: *This story has been updated to include comments from David Patton, president of MISO market monitor Potomac Economics.*

Department of Energy
Washington, DC 20585

June 16, 2025

The Honorable Brett Guthrie
Chairman, Committee on Energy and Commerce
U.S. House of Representatives
Washington, DC 20515

Dear Mr. Chairman:

Enclosed please find a copy of the Charter re-establishing the National Coal Council (NCC).

In accordance with Section 9 of the Federal Advisory Committee Act, this Committee will serve and support the Department of Energy. If you have any questions, please contact Mr. Shawn Affolter, Principal Deputy Assistant Secretary, Office of Congressional and Intergovernmental Affairs, 202-586-5450.

Sincerely,

David Borak

David A. Borak
Committee Management Officer

Enclosure

cc: The Honorable Frank Pallone Jr.
Ranking Member

Industrial Energy Consumers of America (IECA)
The Voice of the Industrial Energy Consumers

1050 Connecticut Avenue, NW, Suite 500 • Washington, D.C. 20036
Telephone (202) 223-1420 • www.ieca-us.org

June 24, 2025

The Honorable Brett Guthrie
Chairman
Committee on Energy and Commerce
U.S. House of Representatives
Washington, DC 20515

The Honorable Frank Pallone
Ranking Member
Committee on Energy and Commerce
U.S. House of Representatives
Washington, DC 20515

Re: H.R. 1949, the "Unlocking our Domestic LNG Potential Act of 2025" is Inconsistent with President Trump's Pledge to Put America First

Dear Chairman Guthrie and Ranking Member Pallone:

On behalf of the Industrial Energy Consumers of America (IECA) we oppose H.R. 1949, the "Unlocking our Domestic LNG Potential Act of 2025." The bill prioritizes LNG exports over U.S. consumers by removing long standing Natural Gas Act consumer protections. We urge Republicans to not vote for this bill which could directly impact manufacturing competitiveness and the 13 million jobs we employ. The stakes are high. For every one dollar increase in the Henry Hub natural gas price, consumers pay on average $34 billion more for natural gas and $20 billion more for electricity, or $54 billion annually.[1] One hundred percent of our member companies are from the manufacturing sector and are price sensitive.

The U.S. Department of Energy (DOE) has already approved a significant volume equal to 48 Bcf/d for shipment to NFTA countries, which equals 51 percent of 2024 net supply.[2] Only 15 Bcf/d is operating. Why then is it in the public interest for Congress to remove consumer protections? This is not a national security issue. What is approved is far more than enough to supply our allies.

States that Should Vote Against H.R. 1949

The most vulnerable are large natural gas consuming states that do not produce much natural gas. These states should not support H.R. 1949 which includes Georgia, Florida, Michigan, North Carolina, Indiana, Tennessee, South Carolina, Iowa, California, New Jersey, New York, Virginia, Oregon, and Alabama.

[1] Natural Gas, U.S. Energy Information Administration (EIA), https://www.eia.gov/naturalgas/
[2] Summary of LNG Export Applications of the Lower 48 States, U.S. Department of Energy, https://www.energy.gov/fecm/articles/summary-lng-export-applications-lower-48-states

U.S. Energy Information Administration (EIA) data proves that LNG export volumes are highest during our winter peak heating season months of November through March, which accelerates a reduction in U.S. inventory, increasing the prices of U.S. natural gas and electricity and reducing reliability. The severity of the problem increases as export capacity increases (see Figures 4-5).

LNG customers are countries who are insensitive to price and will pay any price to keep the lights on in their country. No matter how high U.S. prices will go, they will buy away our natural gas even when our winter inventories fall and prices rise. The LNG 20-year contracts shift supply and price risk from LNG buying countries to U.S. consumers and the economy. No U.S. entity has 20-year contracts, not even electric utilities.

We urge you to vote against H.R. 1949 and preserve consumer protections.

Sincerely,

Paul N. Cicio
Paul N. Cicio
President & CEO

cc: U.S. House

The Industrial Energy Consumers of America is a nonpartisan association of leading manufacturing companies with $1.3 trillion in annual sales, over 12,000 facilities nationwide, and with more than 1.9 million employees. One hundred percent of IECA members are manufacturing companies whose competitiveness is largely determined by the cost and reliability of natural gas and electricity. IECA's sole mission is to reduce and avoid energy costs and increase energy reliability through advocacy in Congress and regulatory agencies, such as the Federal Energy Regulatory Commission (FERC). IECA membership represents a diverse set of industries including chemicals, plastics, steel, iron ore, aluminum, paper, food processing, fertilizer, insulation, glass, industrial gases, pharmaceutical, consumer goods, building products, automotive, independent oil refining, and cement.

Figure 1

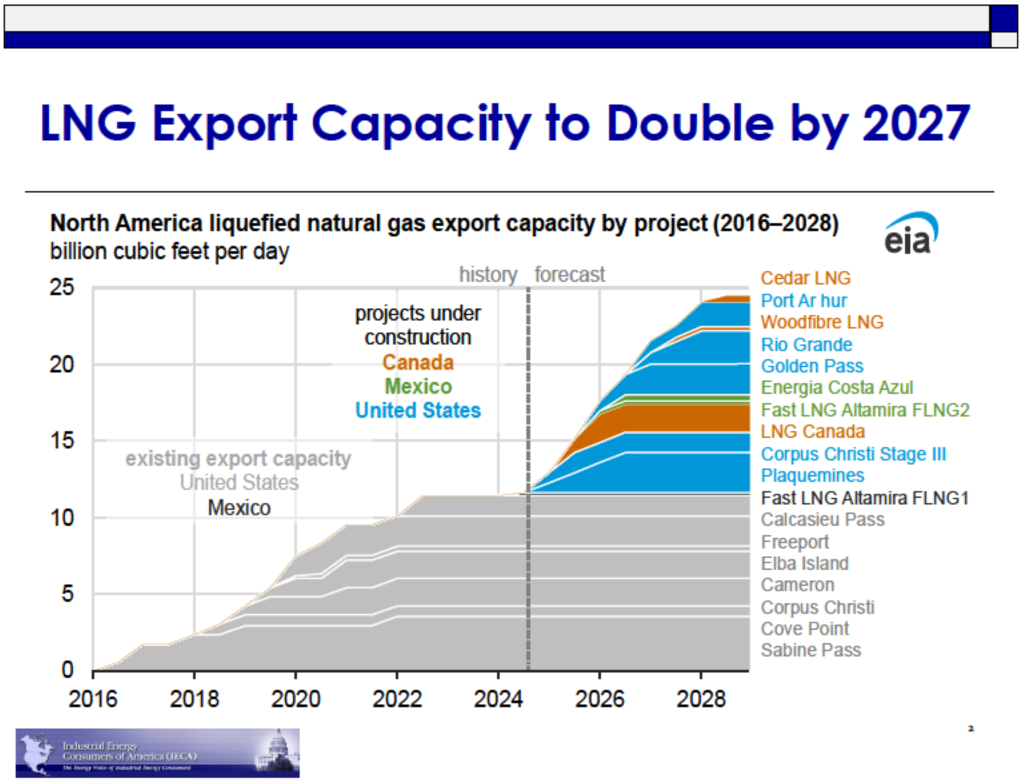

Figure 2

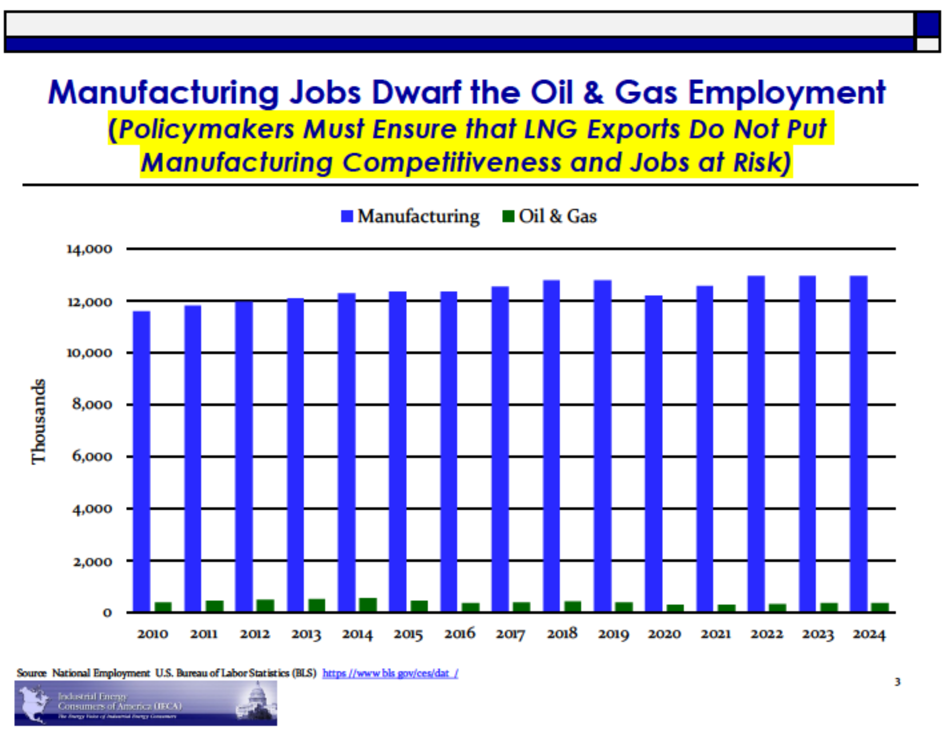

Figure 3

Seasonality Plays a Far Bigger Role in Natural Gas than Oil Products (EIA)

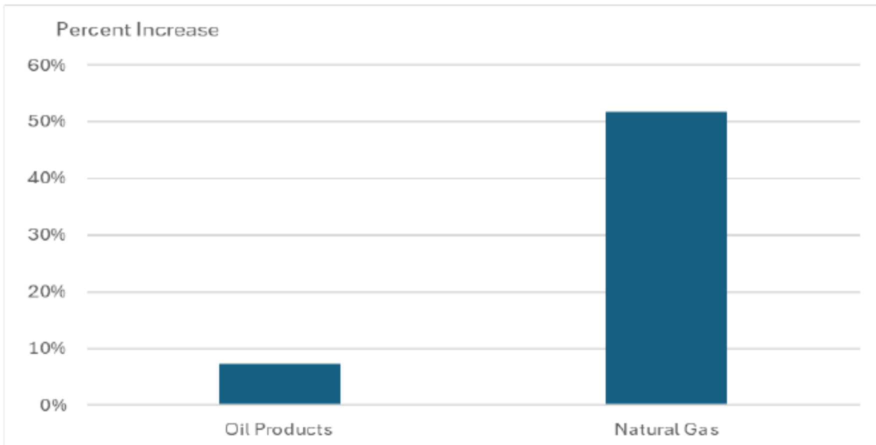

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Figure 4

LNG Exports are Highest During Winter Months Which Increases Natural Gas and Electricity Prices (EIA)

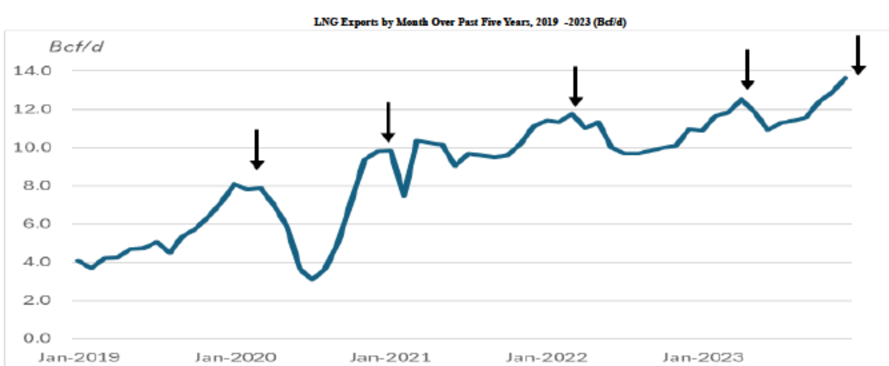

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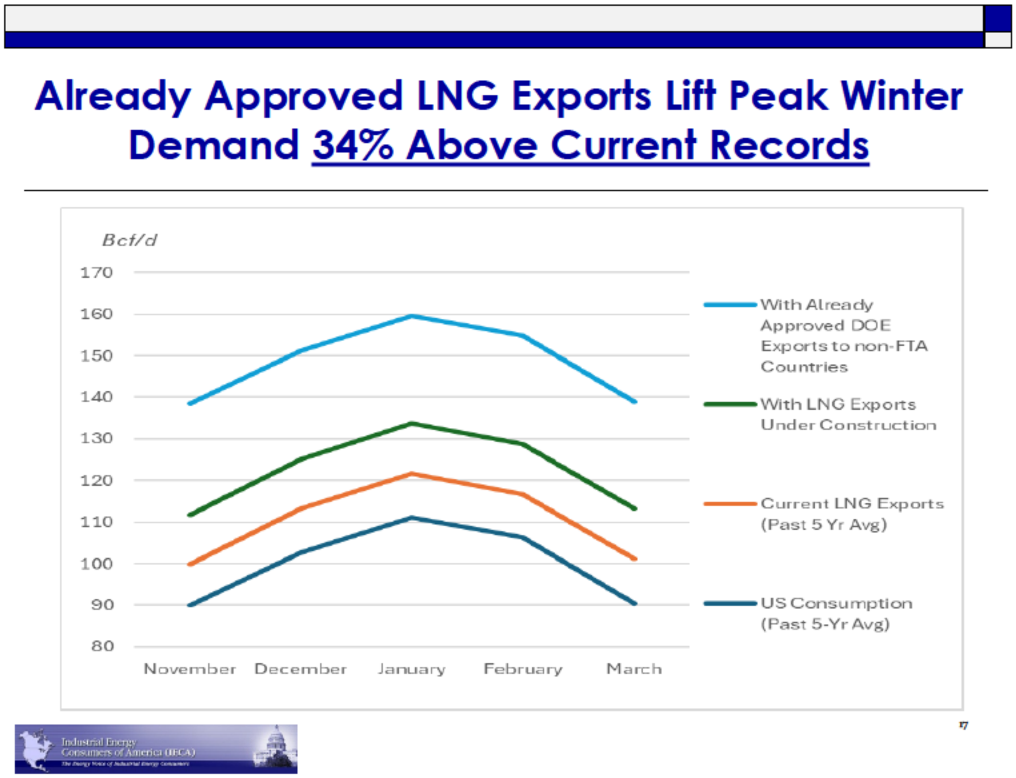
Figure 5


Already Approved LNG Exports Lift Peak Winter Demand 34% Above Current Records
Bcf/d
170
160
150
140
130
120
110
100
90
80
November
December
January
February
March
With Already Approved DOE Exports to non-FTA Countries
With LNG Exports Under Construction
Current LNG Exports (Past 5 Yr Avg)
US Consumption (Past 5-Yr Avg)

LAZARD

LCOE+

LEVELIZED COST OF ENERGY+

June 2025

WITH SUPPORT FROM

Teneo

Roland Berger

Table of Contents

I Executive Summary

Executive Summary—Selected Key Findings from Lazard's 2025 LCOE+

Lazard's 2025 LCOE+ Report is organized around three key areas: Energy Generation, Energy Storage and the Energy System

Energy Generation

Levelized Cost of Energy Version 18.0

- **Renewables Remain Competitive:** On an unsubsidized $/MWh basis, renewable energy remains the most cost-competitive form of generation. As such, renewable energy will continue to play a key role in the buildout of new power generation in the U.S. This is particularly true in the current high power demand environment, where renewables stand out as both the lowest-cost and quickest-to-deploy generation resource
- **Increasing Competitiveness of Existing Gas Generation:** The gap between the LCOE of new wind and solar and the marginal cost of operating CCGTs has widened due to, among other things, persistent low gas prices, high energy demand and increasing renewable LCOEs
- **Significant Shifts Expected:** Unless otherwise indicated, Lazard's LCOE is an LTM analysis focused on "today" and is not a forecasting tool. As such, the outcomes included herein are representative of current development and construction timelines, which vary by technology. For example, while this year's analysis shows only a slight increase in the LCOE of CCGTs, turbine shortages, rising costs and long lead times are expected to drive steep LCOE increases for gas technologies in the near term, as illustrated herein. Additionally, cost declines across Vogtle units 3 and 4 indicate nuclear is poised to benefit from scale and development efficiencies

Energy Storage

Levelized Cost of Storage Version 10.0

- **Storage Cost Decline:** This year's analysis shows notable declines in the LCOS of utility scale and C&I battery energy storage systems. Key drivers of such results include both market dynamics (e.g., lower-than-expected EV demand and the resulting oversupply of cells) and technological advancements (e.g., increased cell capacity and energy density)
- **Tariffs Increase Uncertainty:** While current pricing is further benefiting from aggressive competition, widening LCOS spreads indicate increased volatility as uncertainty related to the ultimate tariff regime is shaping market dynamics in real time. For example, supply chain relocation to Southeast Asia and India is well underway, and market participants are executing on forward procurement strategies to mitigate future pricing risk
- **Market Expansion Is Underway:** The LCOS value snapshots show increased returns reflecting the confluence of lower costs and higher prices in several regions. Energy storage adoption is expanding beyond ISO/RTO-driven wholesale markets and into states where municipal procurement and data center growth is prevalent (e.g., Arizona, Colorado, Florida). Lazard expects continued expansion as backup power and grid resilience become increasingly important in high-growth markets

Energy System

Cost of Firming Intermittency

- **Firming Value Rises as Renewable Penetration Increases:** The cost of firming helps grid operators evaluate resources based on a region's existing generation mix and load characteristics, ensuring the right balance between reliability and affordability. The results of this year's firming analysis show that as the penetration of low-cost intermittent generation increases, the value of firm capacity rises
- **ISO Approaches to System Analysis Are Evolving:** Several independent system operators are adjusting their capacity accreditation methodologies in ways that are generally increasing firming costs. Both CAISO and PJM have reduced capacity accreditation values for highly correlated resources (e.g., solar and shorter-duration storage). Continued development of more sophisticated capacity accreditation frameworks, such as incorporation of seasonal adjustments or diversity benefits, could have material impacts on future firming costs
- **Diverse Generation Sources and Innovation Are Needed:** The results of Lazard's LCOE+ have consistently supported deploying a diverse mix of energy resources. Despite the sustained unsubsidized cost competitiveness of renewable energy, resource planning metrics indicate diverse generation fleets will be required over the long term to meet power needs, likely bolstered by now-emerging technologies such as long duration energy storage, geothermal, nuclear small modular reactors, pumped storage hydropower and carbon capture and storage, among others

II Energy Generation

CONFIDENTIAL

LCOE

Lazard's Levelized Cost of Energy Analysis—Version 18.0

LAZARD

Introduction

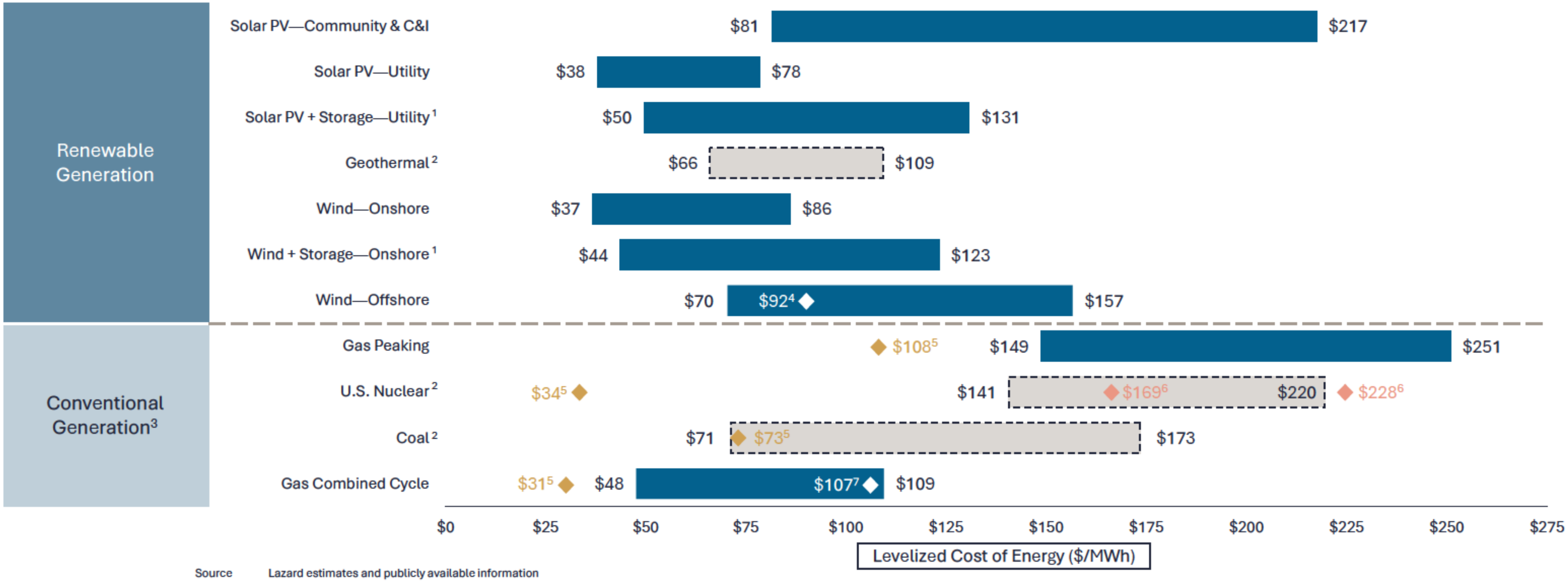
Lazard's Levelized Cost of Energy analysis addresses the following topics:

- 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
- Historical LCOE comparison of various technologies
- Illustration of the historical LCOE declines for onshore wind and utility-scale solar
- 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
  - 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

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, may include: recent tariff-related cost impacts; implementation and interpretation of the full scope of the IRA; economic policy, transmission queue reform, network upgrades and other transmission matters, congestion, curtailment 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 is intended to represent a snapshot in time and utilizes a wide, but not exhaustive, sample set of Industry data. As such, we recognize and acknowledge the likelihood of results outside of our ranges. Therefore, this analysis is not a forecasting tool and should not be used as such given the complexities of our evolving Industry, grid and resource needs. Except as illustratively sensitized herein, this analysis does not consider the intermittent nature of selected renewables energy technologies or the related grid impacts of incremental renewable energy deployment. 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., airborne pollutants, greenhouse gases, etc.).

Levelized Cost of Energy Comparison—Version 18.0

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



Source Lazard estimates and publicly available information

Note Here and throughout this analysis, 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 Reflects the LCOE for a system composed of standalone generation plus standalone storage less the combined system-level synergies (assumed to be 10% of storage capital costs and 25% of inverter costs) The synergies capture potential cost reductions or efficiency gains from integrating generation and storage, such as shared interconnection infrastructure, improved energy dispatch, enhanced capacity utilization and operational efficiencies

2 Given the limited public and/or observable data available for new-build geothermal, coal and nuclear projects, the LCOE presented herein reflects Lazard's LCOE v14 0 results adjusted for inflation and, for nuclear, are based on then-estimated costs of the Vogtle Plant Coal LCOE does not include cost of transportation and storage

3 The fuel cost assumptions for Lazard's LCOE analysis of gas-fired generation, coal-fired generation and nuclear generation resources are $3 45/MMBTU, $1 47/MMBTU and $0 85/MMBTU, respectively, for year-over-year comparison purposes See page titled "Levelized Cost of Energy Comparison—Sensitivity to Fuel Prices" for fuel price sensitivities

4 Represents the illustrative midpoint LCOE for Dominion's Coastal Virginia Offshore Wind ("CVOW") project, based on the publicly disclosed capital cost of ~$8 7 billion (excluding onshore transmission costs) and offshore wind estimates from Lazard Dominion's projected LCOE for CVOW as of February 2025 is $91/MWh in 2027 dollars, with an expected COD in 4Q 2026

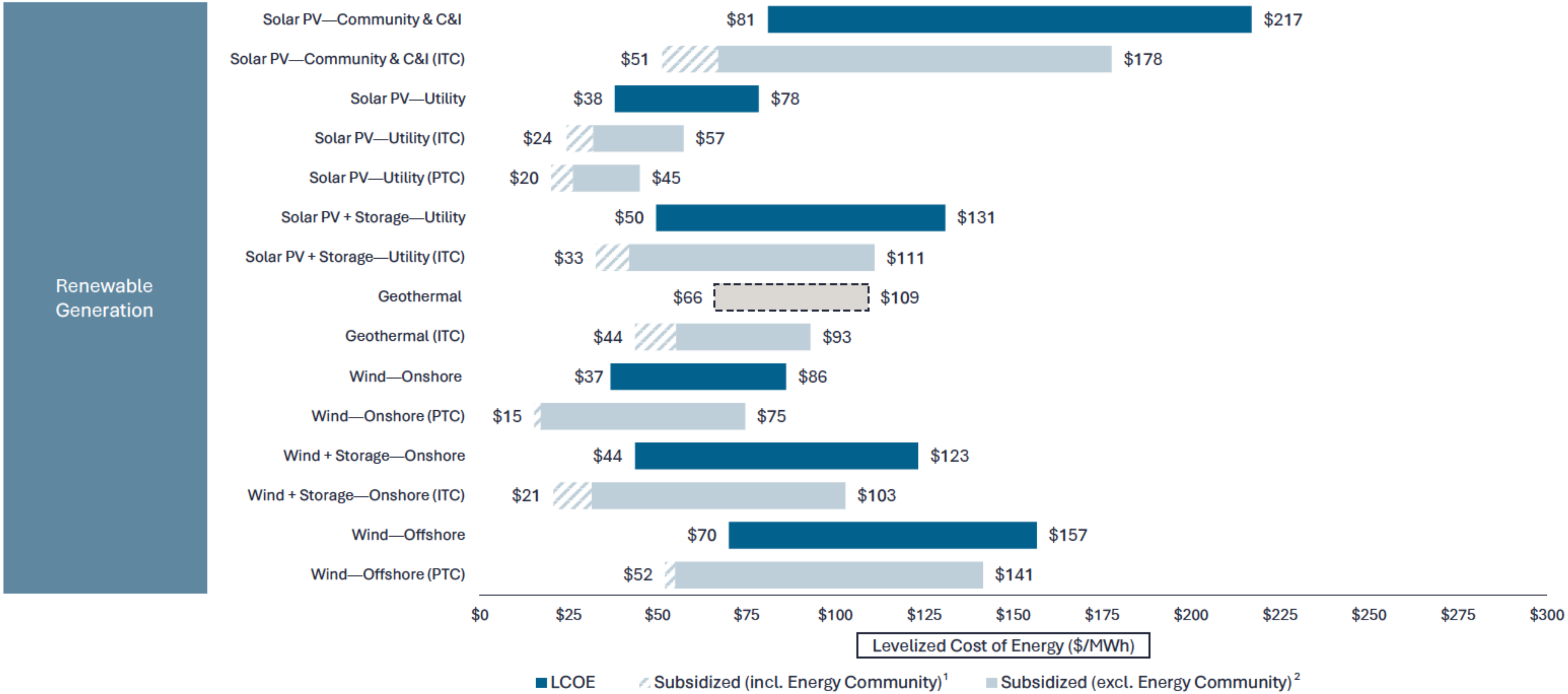
5 Reflects the average of the high and low LCOE marginal cost of operating fully depreciated gas peaking, gas combined cycle, coal and nuclear facilities, inclusive of decommissioning costs for nuclear facilities Analysis assumes that the salvage value for a decommissioned gas or coal asset is equivalent to its decommissioning and site restoration costs Inputs are derived from a benchmark of operating gas, 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—New Build Renewable Generation vs Marginal Cost of Conventional Generation" for additional details

6 Represents illustrative LCOE values for Vogtle nuclear plant's units 3 and 4 The analysis is based on publicly available estimates and suggestions from selected industry experts, indicating a cost "learning curve" of ~30% between Vogtle units 3 and 4 Analysis assumes total operating capacity of ~2 2 GW, total capital cost of ~$32 3 billion, capacity factor of ~97%, operating life of 70 years and other operating parameters estimated by Lazard's LCOE v14 0 results, adjusted for inflation

7 Illustrative high case reflects elevated capital costs ($2,400/kW – $2,600/kW) based on recently observed market quotes for CCGT projects in early stages of development (post-2028 COD)

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

The Investment Tax Credit ("ITC"), Production Tax Credit ("PTC") and Energy Community adder, among other provisions in the IRA, are important components of the LCOE for renewable energy technologies



Source: Lazard estimates and publicly available information

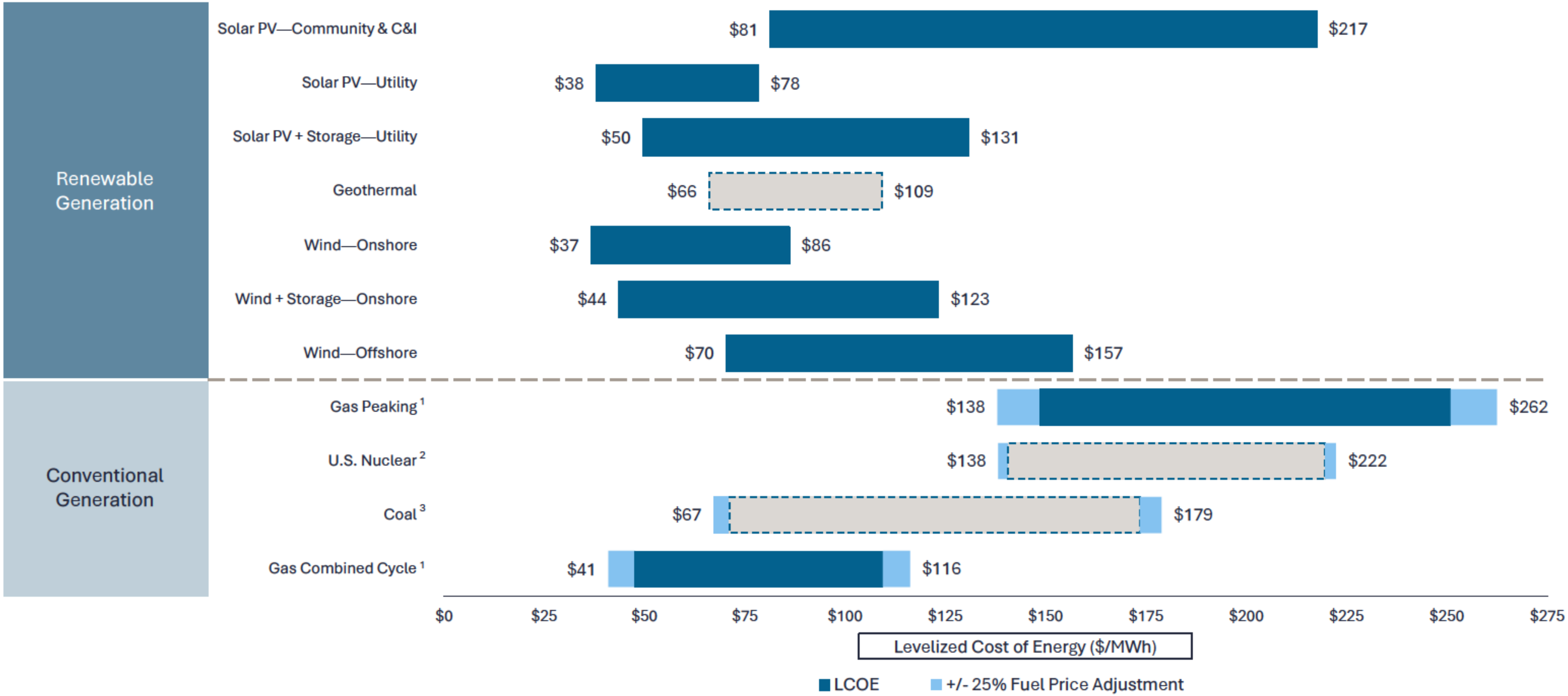
Note: Unless otherwise indicated, this analysis does not include other state or federal subsidies (e g , domestic content adder, etc) The IRA is a comprehensive and evolving piece of legislation that is still being implemented and remains subject to interpretation—important elements of the IRA are not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

1 This sensitivity analysis assumes that projects qualify for the full ITC/PTC, have a capital structure that includes sponsor equity, debt and tax equity and assumes the equity owner has taxable income to monetize the tax credits and also includes an Energy Community adder of 10% for ITC projects and $3/MWh for PTC projects

2 This sensitivity analysis assumes that projects qualify for the full ITC/PTC, have a capital structure that includes sponsor equity, debt and tax equity and assumes the equity owner has taxable income to monetize the tax credits

Levelized Cost of Energy Comparison—Sensitivity to Fuel Prices

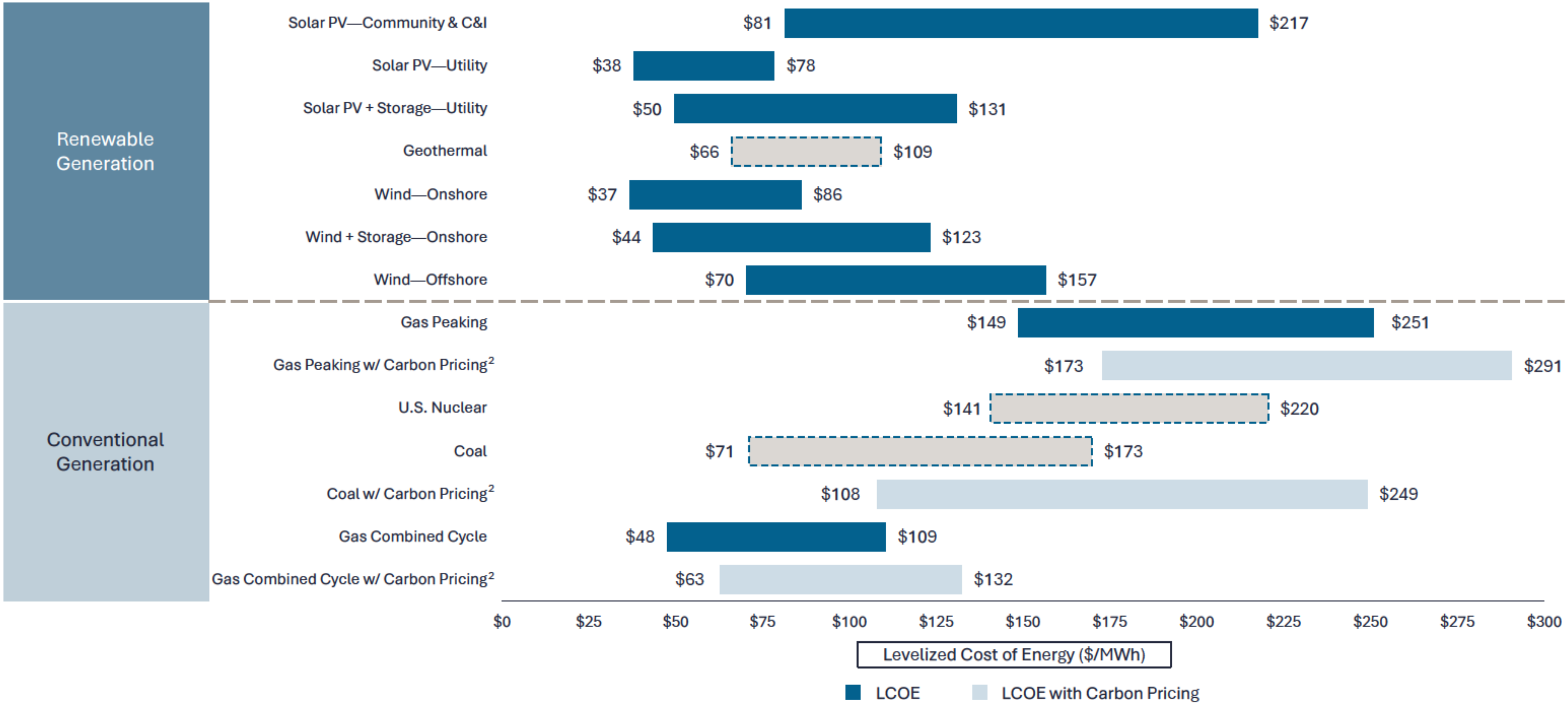
Variations in fuel prices can materially impact the LCOE of conventional generation technologies



Source Lazard estimates and publicly available information
Note Unless otherwise noted, the assumptions used in this sensitivity correspond to those used in the LCOE analysis as presented on the page titled "Levelized Cost of Energy Comparison—Version 18 0"
1 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 LCOE)
2 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 85/MMBTU used in the LCOE)
3 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 LCOE)

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 $40 – $60/Ton[1] of carbon would increase the LCOE for certain conventional generation technologies, as indicated below



Source Lazard estimates and publicly available information

Note Unless otherwise noted, the assumptions used in this sensitivity correspond to those used in the LCOE analysis as presented on the page titled "Levelized Cost of Energy Comparison—Version 18 0" LCOE with Carbon Pricing is limited to carbon emissions directly related to generation and does not include the impacts of carbon pricing on embodied carbon

1 The current administration no longer maintains an estimate of the monetized impacts of greenhouse gas emissions Previous administrations estimated the social cost of carbon to range from $5/Ton (first Trump Administration) to over $200/Ton (Biden Administration)

2 The low and high ranges reflect the LCOE of selected conventional generation technologies including an illustrative carbon price of $40/Ton and $60/Ton, respectively

Levelized Cost of Energy Comparison—Sensitivity to Cost of Capital[1]

A key consideration in determining the LCOE for utility-scale generation technologies is the cost, and availability, of capital[1]. In practice, this dynamic is particularly significant because the cost of capital for each asset is related to its specific operational characteristics and the resulting risk/return profile

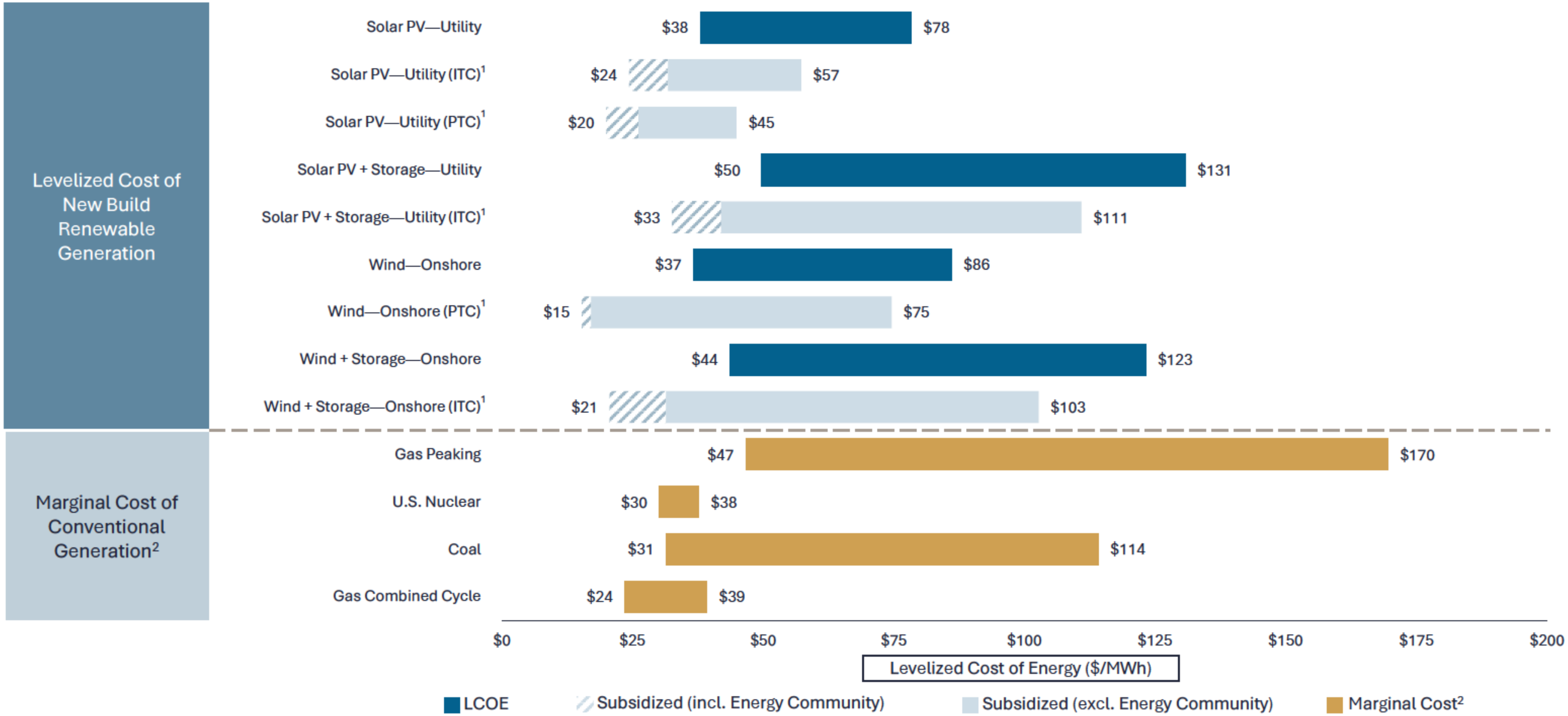
Average LCOE[2]

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 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—Version 18 0"
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
3 Given the limited public and/or observable data available for new-build nuclear projects, the LCOE presented herein reflects Lazard's LCOE v14 0 results adjusted for inflation and are based on then-estimated costs of the Vogtle Plant

Levelized Cost of Energy Comparison—New Build Renewable Generation vs. Marginal Cost of Conventional Generation

Certain renewable energy generation technologies have an LCOE that is competitive with the marginal cost of selected conventional generation technologies—notably, as incremental, intermittent renewable energy capacity is deployed and baseload gas-fired generation utilization rates increase, this gap closes, particularly in low gas pricing and high energy demand environments

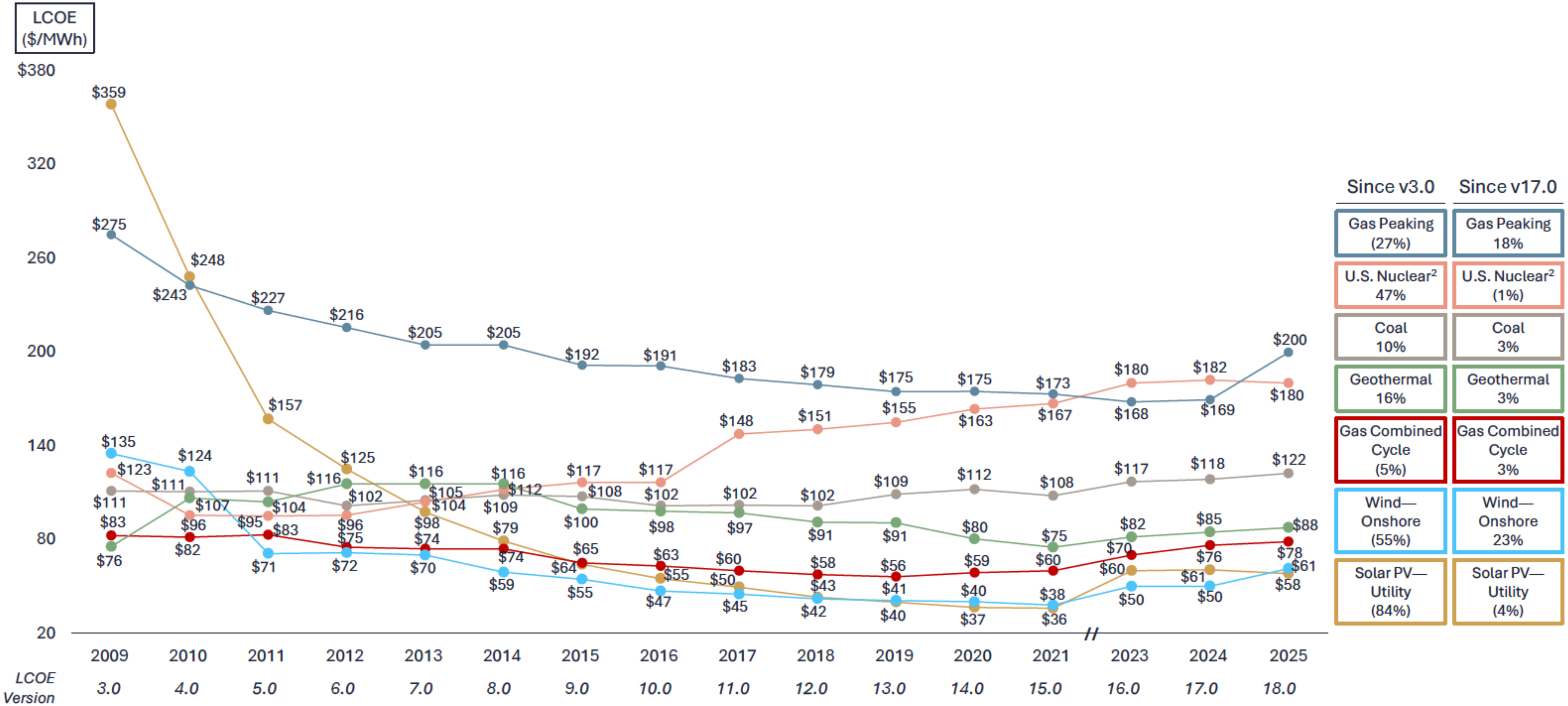


Source Lazard estimates and publicly available information
Note Unless otherwise noted, the assumptions used in this sensitivity correspond to those used on page titled "Levelized Cost of Energy Comparison—Version 18 0"
1 See page titled "Levelized Cost of Energy Comparison—Sensitivity to U S Federal Tax Subsidies" for additional details
2 Reflects the marginal cost of operating fully depreciated gas, coal and nuclear facilities, inclusive of decommissioning costs for nuclear facilities Analysis assumes that the salvage value for a decommissioned gas or coal asset is equivalent to its decommissioning and site restoration costs Inputs are derived from a benchmark of operating gas, 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

Levelized Cost of Energy Comparison—Historical LCOE Comparison

Lazard's LCOE analysis indicates significant historical cost declines for utility-scale renewable energy generation technologies, which has begun to level out and even slightly increase in recent years

Selected Historical Average LCOE Values[1]



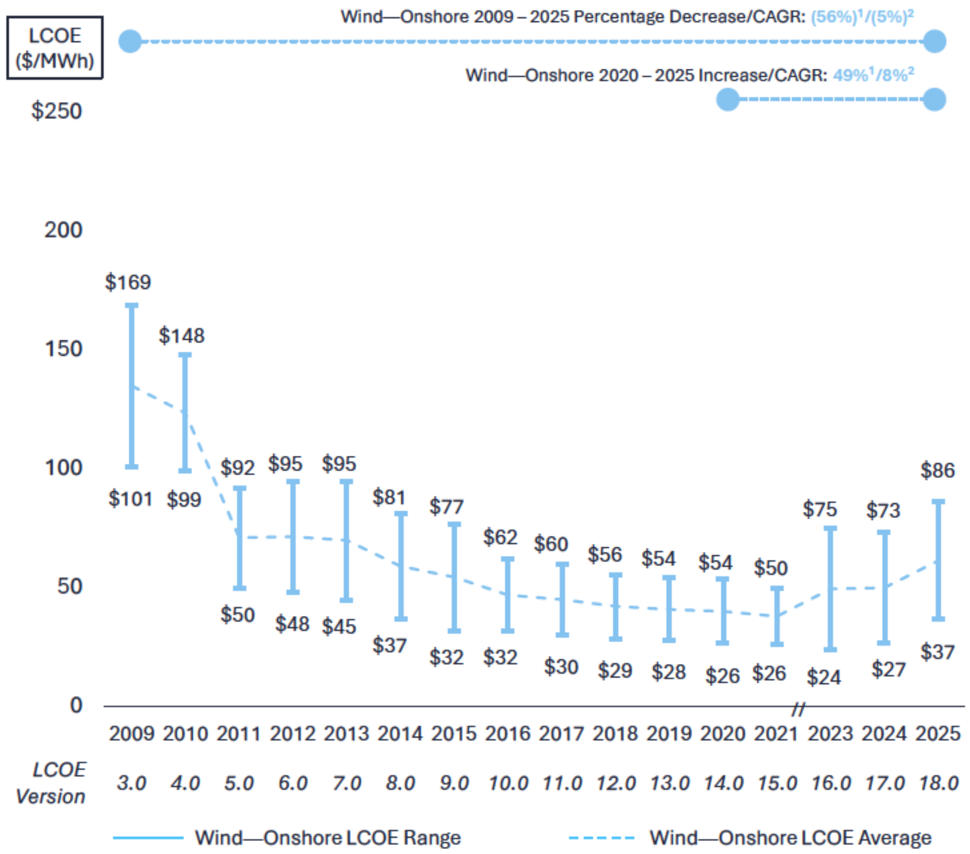
Source: Lazard estimates and publicly available information

1. Reflects the average of the high and low LCOE for each respective technology in each respective year Percentages represent the total change in the average LCOE since Lazard's LCOE v3 0 and LCOE v17 0, respectively
2. Given the limited public and/or observable data available for new-build nuclear projects, the LCOE presented herein reflects Lazard's LCOE v14 0 results adjusted for inflation and are based on then-estimated costs of the Vogtle Plant

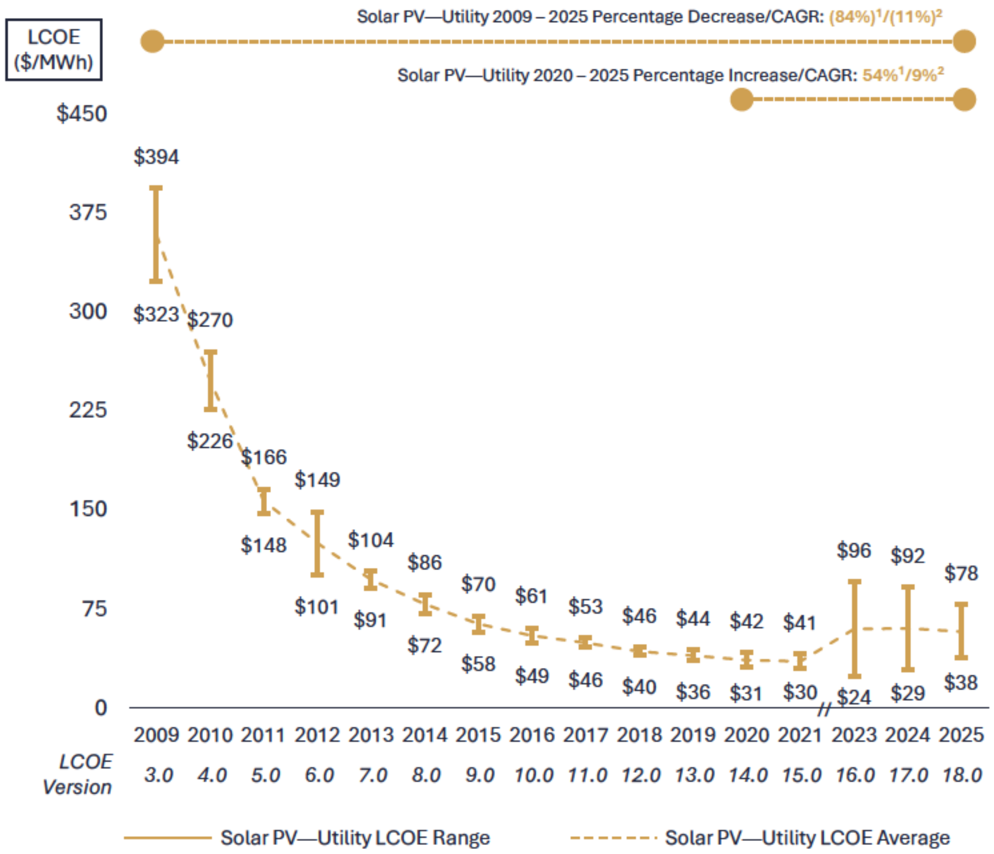
Levelized Cost of Energy Comparison—Historical Renewable Energy LCOE

This year's analysis shows a divergence in trends between wind and solar with solar costs declining slightly and wind costs increasing, likely reflecting the difference in supply chain conditions across each technology

Wind—Onshore



Solar PV—Utility



Source: Lazard estimates and publicly available information
1 Reflects the average percentage increase/(decrease) of the high end and low end of the LCOE range
2 Reflects the average compounded annual growth rate of the high end and low end of the LCOE range

III Energy Storage

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Lazard's Levelized Cost of Storage Analysis—Version 10.0

LAZARD

Introduction

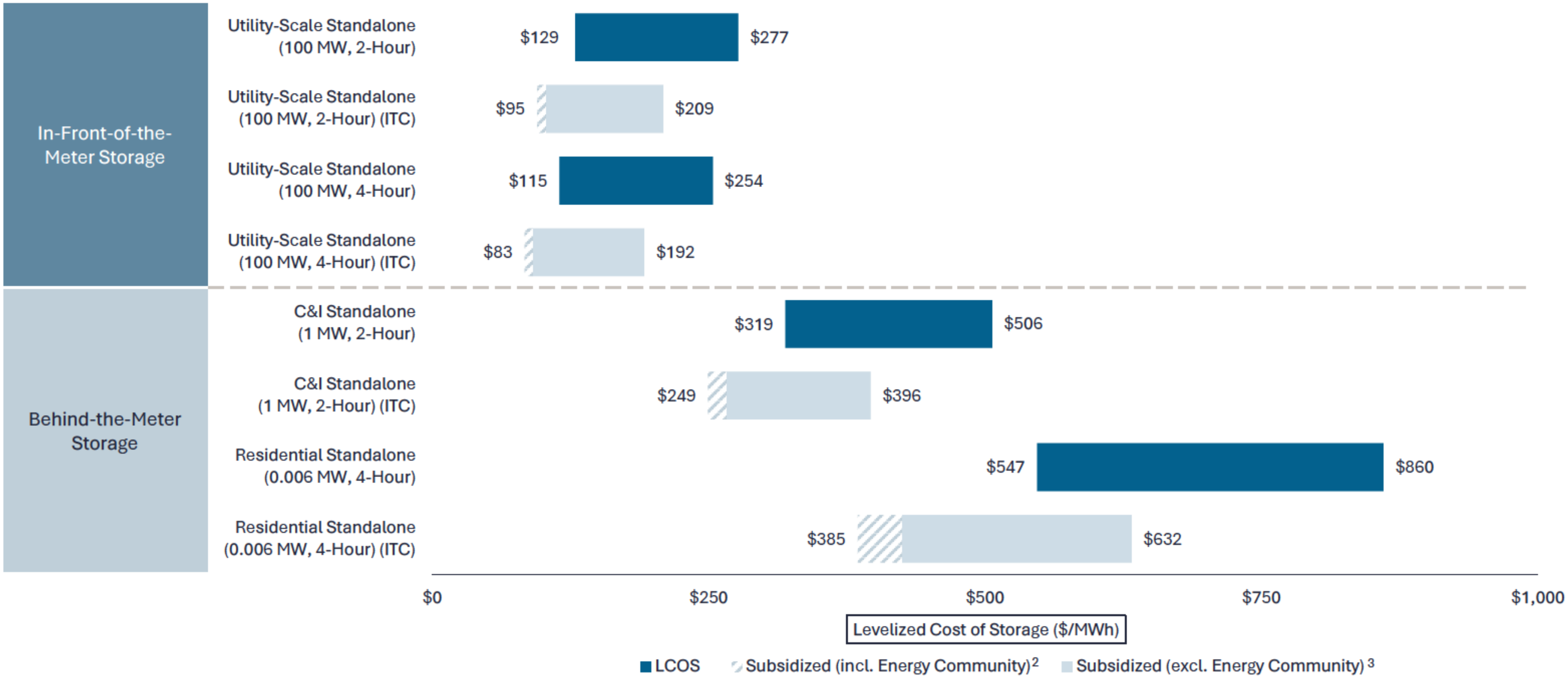
Lazard's Levelized Cost of Storage analysis addresses the following topics:

- LCOS Analysis:
  - Comparative LCOS analysis for various energy storage systems on a $/MWh basis
  - Comparative LCOS analysis for various energy storage systems on a $/kW-year basis
- Storage Value Snapshot Case Studies:
  - Overview of potential revenue applications for various energy storage systems
  - Overview of the Storage Value Snapshot Case Studies analysis and identification of selected geographies for each use case analyzed
  - Results from the Storage Value Snapshot Case Studies analysis
- Appendix Materials, including:
  - An overview of the use cases and operational parameters of selected energy storage systems for each use case analyzed
  - An overview of the methodology utilized to prepare Lazard's LCOS analysis
  - A summary of the assumptions utilized in Lazard's LCOS analysis
  - Deconstruction of the LCOS for various generation technologies by capital cost, fixed operations and maintenance ("O&M") expense and charging cost

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, may include: recent tariff-related cost impacts; implementation and interpretation of the full scope of the IRA; economic policy, transmission queue reform, network upgrades and other transmission matters; congestion, curtailment 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.). This analysis is intended to represent a snapshot in time and utilizes a wide, but not exhaustive, sample set of Industry data. As such, we recognize and acknowledge the likelihood of results outside of our ranges. Therefore, this analysis is not a forecasting tool and should not be used as such given the complexities of our evolving Industry, grid and resource needs.

Levelized Cost of Storage Comparison—Version 10.0 ($/MWh)

Lazard's LCOS analysis evaluates standalone energy storage systems on a levelized basis to derive cost metrics across energy storage use cases and configurations[1]



Source Lazard estimates and publicly available information

Note Here and throughout this section, unless otherwise indicated, the 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 Capital costs include 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 not included in capital costs in this analysis and vary across use cases due to usage profiles and lifespans Charging costs are assessed at the weighted average hourly pricing (wholesale energy prices) across an optimized annual charging profile of the asset See Appendix B for charging cost assumptions and additional details The projects are assumed to use a 5-year MACRS depreciation schedule

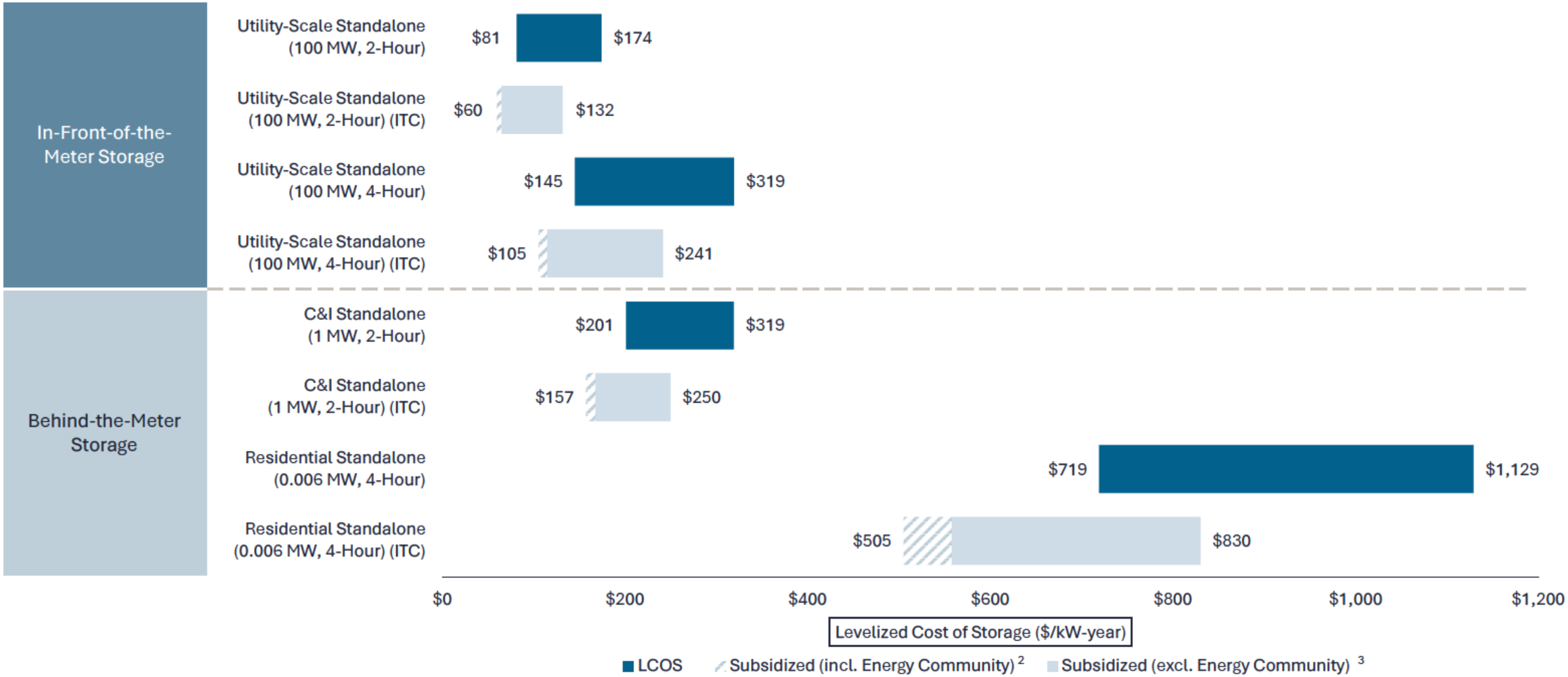
1 See Appendix B for a detailed overview of the use cases and operational parameters analyzed in the LCOS

2 This sensitivity analysis assumes that projects qualify for the full ITC and have a capital structure that includes sponsor equity, debt and tax equity and also includes a 10% Energy Community adder

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

Levelized Cost of Storage Comparison—Version 10.0 ($/kW-year)

Lazard's LCOS analysis evaluates standalone energy storage systems on a levelized basis to derive cost metrics across energy storage use cases and configurations[1]

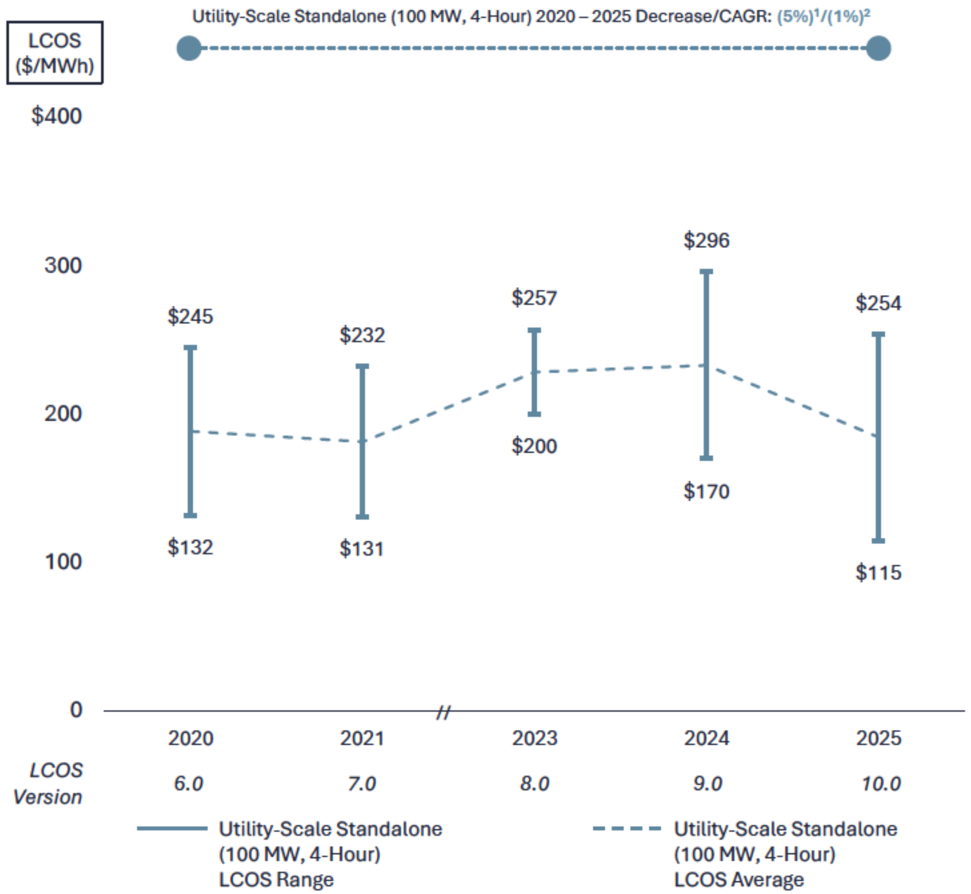


Source: Lazard estimates and publicly available information
1 See Appendix B for a detailed overview of the use cases and operation parameters analyzed in the LCOS
2 This sensitivity analysis assumes that projects qualify for the full ITC and have a capital structure that includes sponsor equity, debt and tax equity and also includes a 10% Energy Community adder
3 This sensitivity analysis assumes that projects qualify for the full ITC and have a capital structure that includes sponsor equity, debt and tax equity

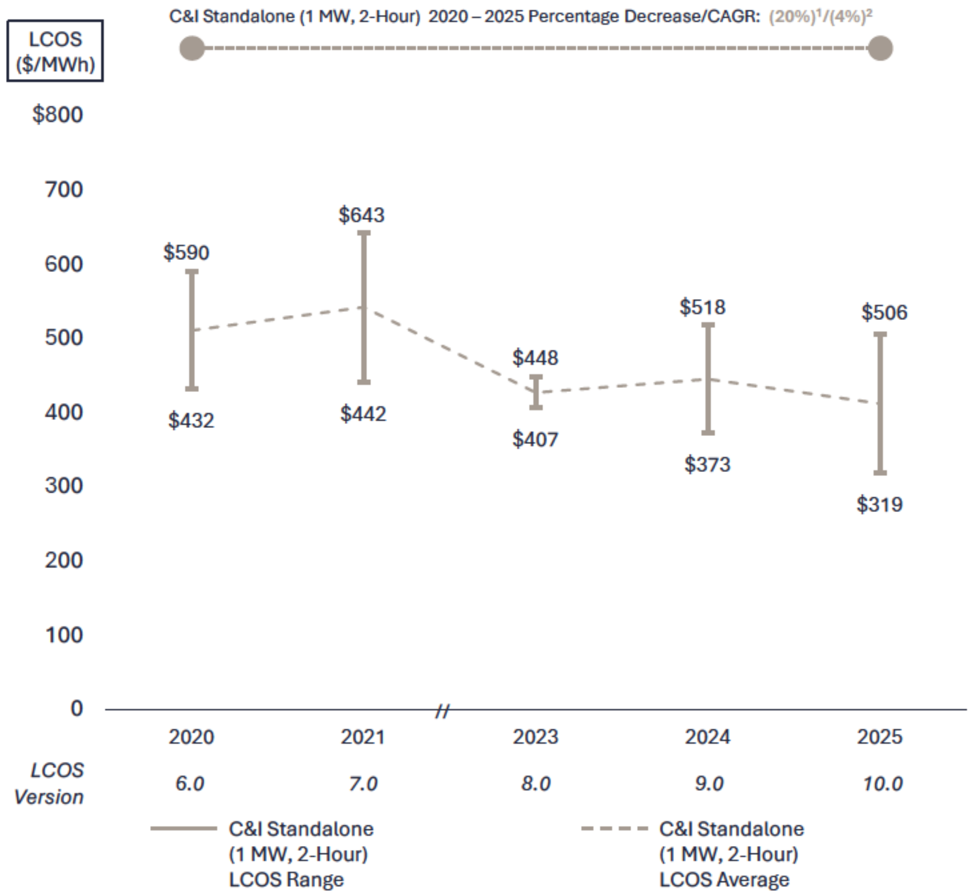
Levelized Cost of Storage Comparison—Historical LCOS Comparison

This year's analysis shows notable declines in the LCOS of utility scale and C&I battery energy storage systems. Key drivers include both market dynamics—slower-than-expected EV demand and the resulting oversupply of cells—and technological advancements, including increased cell capacity and energy density

Utility-Scale Standalone (100 MW, 4-Hour)



C&I Standalone (1 MW, 2-Hour)



Source: Lazard estimates and publicly available information
Note: The methodology for the Levelized Cost of Storage has evolved between v1 0 and v10 0 given technological advances and data availability Page presents the most comparable Utility-Scale and C&I Standalone storage technologies included in the Levelized Cost of Storage report for that year
1 Reflects the average percentage increase/(decrease) of the high end and low end of the LCOS range
2 Reflects the average compounded annual growth rate of the high end and low end of the LCOS range

Storage Value Snapshot Case Studies—Revenue Potential for Selected Use Cases

The 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

			Use Cases[1]				
		Description	Utility-Scale Standalone	Utility-Scale PV + Storage	Utility-Scale Wind + Storage	Commercial & Industrial Standalone	Commercial & Industrial PV + Storage
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 (4-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	Incentives	• Payments provided to residential and commercial customers to encourage the acquisition and installation of energy storage systems				✓	✓

Source Lazard estimates 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 Storage Value Snapshot Case Studies

Storage Value Snapshot Case Studies—Overview

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

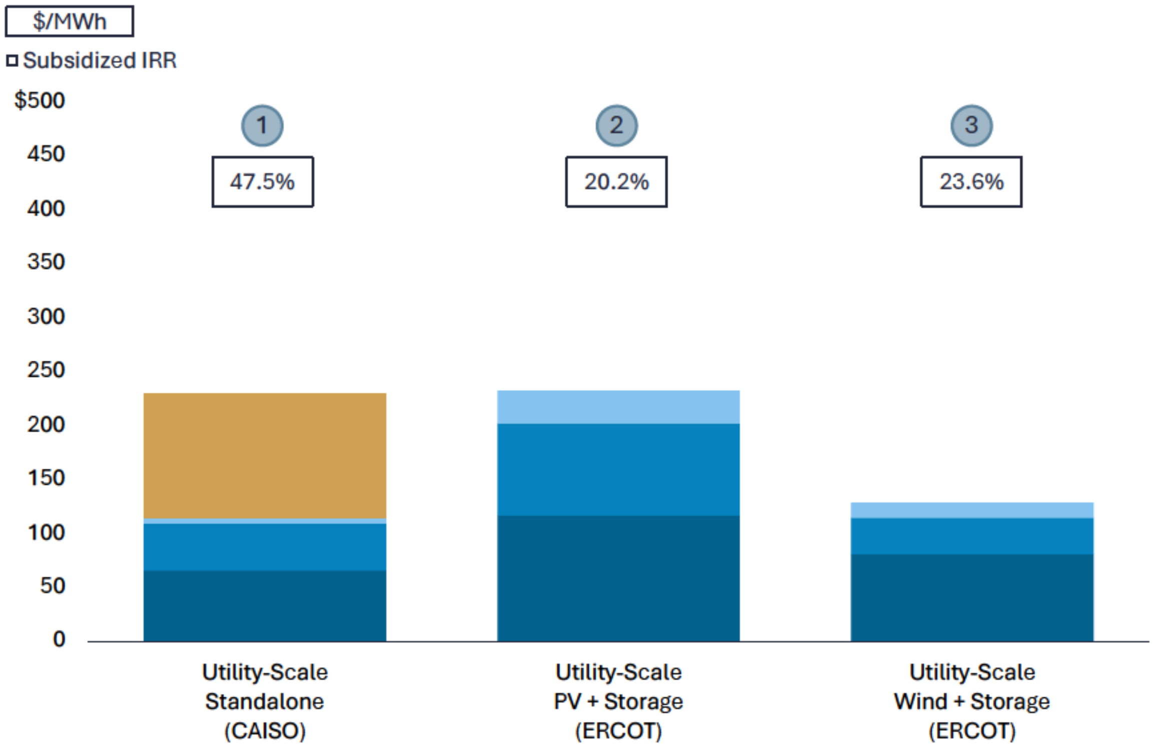
		Location	Description	Storage (MW)	Generation (MW)	Storage Duration (hours)	Revenue Streams
In-Front-of-the-Meter Storage	1 Utility-Scale Standalone	CAISO[1] (SP-15)	Large-scale energy storage system	100	–	4	• Energy Arbitrage • Frequency Regulation • Resource Adequacy • Spinning/Non-Spinning Reserves
	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 Storage	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, Demand Response Participation, Avoided Costs to Commercial Customer and Local Capacity Resource Programs
	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	

Source Lazard estimates 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 the Pacific Gas & Electric Company

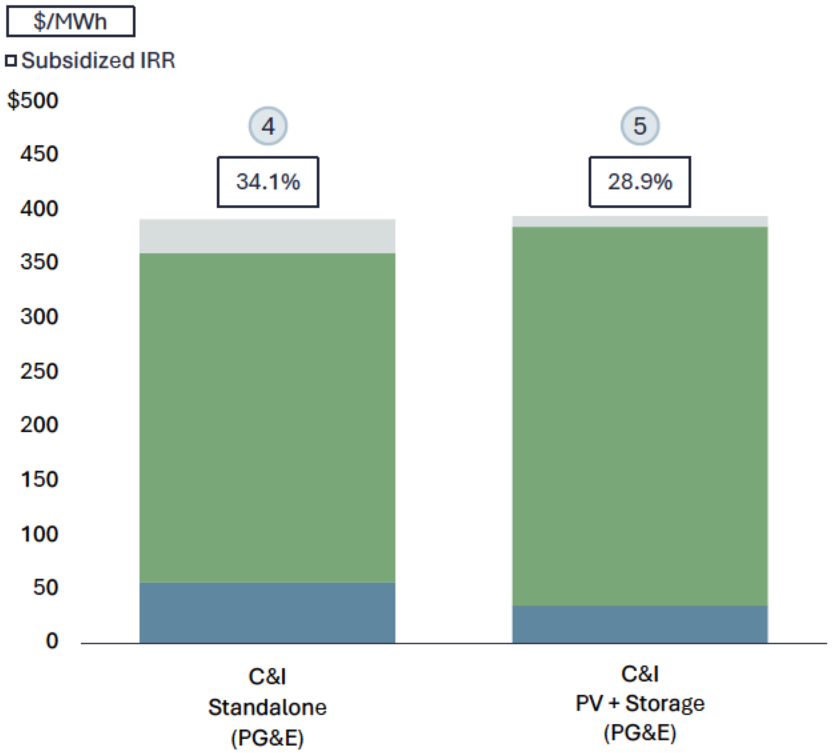
Storage Value Snapshot Case Studies—Results

Project economics evaluated in the Storage Value Snapshot Case Studies 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. Notably, this year capacity/resource adequacy payments nearly doubled which, combined with LCOS declines, significantly increased project returns

In-Front-of-the-Meter Storage



Behind-the-Meter Storage



■ Energy Arbitrage[1] ■ Frequency Regulation ■ Spinning/Non-Spinning Reserves ■ Capacity/Resource Adequacy ■ Demand Response—Utility ■ Bill Management ■ Local Incentive Payments

Source: Lazard estimates 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 page titled "Levelized Cost of Storage Comparison—Version 10 0 ($/MWh)", which are more broadly representative of U S storage market conditions as opposed to location-specific conditions Levelized revenues in all cases are gross revenues (not including 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 and/or storage and $27 50/MWh federal PTC for wind 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 December 31, 2024 Revenues for Value Snapshots (4) – (5) are based on the most recent tariffs, programs and incentives available as of February 1, 2025

1 In previous versions of this analysis, Energy Arbitrage was referred to as Wholesale Energy Sales

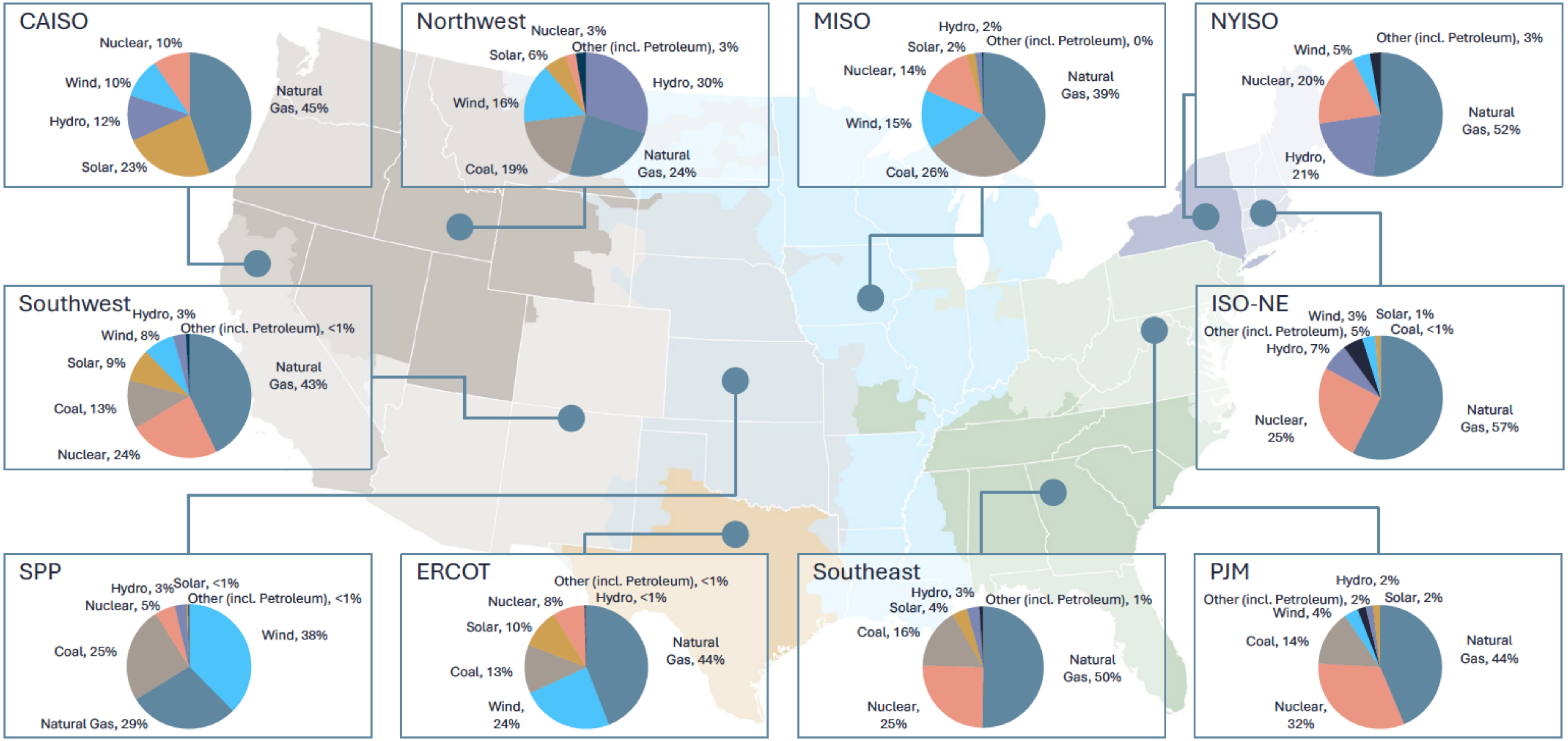
IV Energy System

Cost of Firming Intermittency

Market Overview—Current Generation Mix

The current generation mix across the U.S. varies significantly by market—resource availability, operational constraints, load profiles, transmission infrastructure, seasonal weather patterns and regulatory constructs, among other factors, are key drivers of such variation

2024 Generation Mix by Region



Source Publicly available information
Note Numbers may not sum due to rounding

Market Overview—Current Firming Cost Frameworks

Many grid operators and utilities use effective load-carrying capability ("ELCC") to measure the reliability of new power generation resources to contribute to the electricity grid at key periods of demand, particularly intermittent ones like wind and solar. Combined with the net cost of new entry ("Net CONE")[1], as determined by the grid operator, ELCC helps to guide decisions on resource planning, capacity adequacy and system reliability. Balancing authorities ("BA"s) such as MISO, CAISO, SPP, PJM and ERCOT have adopted ELCC accreditation frameworks to ensure a reliable and efficient grid

- ELCC measures the performance of a resource at times of greatest "capacity need" for the system, where capacity need is a function of electricity demand patterns and the generation mix in each region—in general, the higher the renewable resource penetration, the lower the ELCC accreditation for each additional renewable resource

	BA-Specified "Firming" Source	ELCC Values[2]	Net CONE[1] ($/kW-month)	Selected Market Commentary
MISO	Natural Gas Peaker	Solar: 39% Wind: 26%	$10.03	• In March 2024, MISO adopted the FERC Reliability Availability and Need ("RAN") seasonal capacity construct for wind and solar resources • Seasonal wind accredited capacity values are 18.1% for summer, 18.6% for fall, 53.1% for winter and 18.0% for spring • Solar capacity values are 50% for all seasons except winter, which is 5%
CAISO	4-Hour Lithium-Ion Battery	Solar: 7% PV + Storage[3]: 41% Wind: 12%	$18.92	• Increasing levels of solar penetration in CAISO have shifted peak demand later in the day, reducing the ELCC value for solar • CAISO significantly reduced ELCC values for 4-hour battery storage systems, driven by significant growth in 4-hour storage capacity
SPP	Natural Gas Peaker	Solar: 51% Wind: 20%	$8.38	• SPP published seasonal accreditation values based on 2024, assigning separate values to resources for summer and winter seasons • Summer wind and solar contributions are 15.2% and 25.5%, respectively, whereas winter values shift to 39.1% for wind and 62.2% for solar
PJM	Natural Gas Peaker	Solar: 12% PV + Storage[3]: 33% Wind: 38%	$10.29	• PJM adopted a new, marginal ELCC methodology to begin in the 2025/2026 delivery year that reduces the reliability value of highly correlated resources, such as solar and short-duration storage[4] • The update is expected to better capture expected resource performance during system peak
ERCOT	Natural Gas Peaker	Solar: 38% Wind: 25%	$9.92	• ERCOT maintains notably high ELCC values despite having the highest renewable penetration by capacity of the U.S. regulatory markets • ERCOT updates its capacity scheme every three years; the most recent publication was December 2022

Source Publicly available information
1 Net "CONE" is defined as capital and operating costs less expected market revenues for a new, firm resource (e g , gas peaker or battery storage) Net CONE is established by the respective balancing authority
2 ELCC values are calculated by the respective balancing authority ELCC is an indicator of the incremental reliability contribution of a given resource to the electricity grid 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 by 0 85 MW of additional firm capacity to represent the addition of 1 MW of firm system capacity Where seasonal accreditation values exist, values have been annualized
3 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 55% to 75% for PJM and CAISO, respectively
4 This year's analysis does not reflect this future methodology

Cost of Firming Intermittency—Methodology

Lazard's Cost of Firming Intermittency analysis builds on the LCOE results by evaluating system-level costs associated with supplementing intermittent renewable energy on the grid with firm capacity to ensure reliable electricity delivery during peak demand periods. The analysis utilizes ELCC and Net CONE values assessed and published by grid operators for each regional market to determine these costs

- The firm capacity value of a new resource is calculated as Nameplate Capacity × ELCC %, where:
  - Nameplate Capacity of a resource refers to its maximum potential energy output, and
  - ELCC measures the performance of a resource at times of greatest "capacity need" for the system, where capacity need is a function of electricity demand patterns and the generation mix in each region
- Over time, increased renewable penetration or changes in demand patterns can shift the timing of the capacity need, impacting ELCC
- The remaining non-firm capacity (Nameplate Capacity × (1 – (ELCC %))) is "firmed" at the Net CONE, a $/kW-month figure which is intended to reflect capital and operating costs less expected market revenues for a new, firm resource (e.g., gas peaker or battery storage)
  - Net CONE is assessed and published by grid operators for each regional market

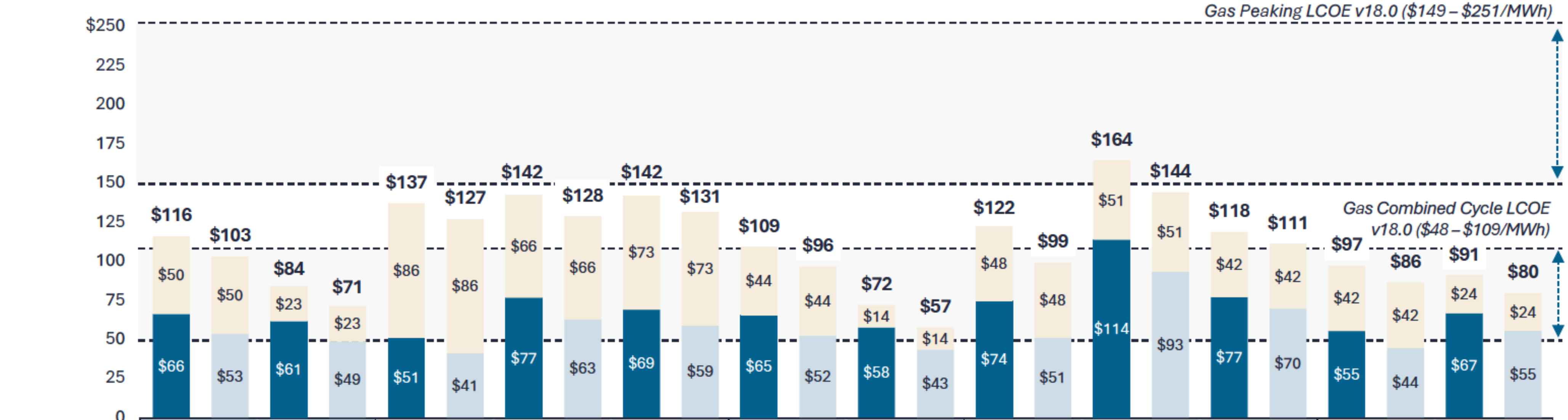
In the following analysis, the Levelized Firming Cost is defined as the additional capacity payment, priced at Net CONE, required to bring the ELCC of the combined system (intermittent and firming resource) to 100%. The LCOE plus Levelized Firming Cost varies between ISOs, due to (1) the standalone LCOE in the region based on regional capacity factor for wind or solar, (2) the ELCC value of the standalone renewable resource and (3) the region's Net CONE

$$\frac{\textbf{Nameplate Capacity (kW)} \times (1 - \textbf{ELCC (\%)}) \times \textbf{Net CONE (\$/kW-month)} \times \textbf{12 Months}}{\textbf{Nameplate Capacity (MW)} \times \textbf{Regional Capacity Factor (\%)} \times \textbf{8,760 Hours}} = \textbf{Levelized Firming Cost (\$/MWh)}$$

Cost of Firming Intermittency—Results

The Cost of Firming Intermittency or "firming cost" is the incremental cost to firm[1] solar, solar + storage or wind resources through additional monthly capacity payments to a firming resource under current regional system planning constructs

LCOE plus Levelized Firming Cost ($/MWh)[2]



	Solar	Wind	Solar	PV + Storage	Wind	Solar	Wind	Solar	PV + Storage	Wind	Solar	Wind
ELCC[3]	39%	26%	7%	41%[4]	12%	51%	20%	38%	33%[4]	38%	38%	25%
Capacity Factor	20%	37%	27%	27%	33%	21%	40%	18%	18%	30%	24%	34%
Resource Penetration	13%	26%	43%	43%	17%	2%	61%	2%	2%	5%	34%	46%
	MISO		CAISO			SPP		PJM			ERCOT	

■ Unsubsidized Regional LCOE[2] ■ Subsidized Regional LCOE (excl. Energy Community)[4,5] ■ Levelized Firming Cost[1]

Source: Lazard estimates and publicly available information

Note: Total, including firming cost, does not represent the cost of building a 24/7 firm resource on a single project site but, instead, the LCOE of a renewable resource and the additional capacity costs required to achieve the resource adequacy requirement in the relevant reliability region based on the net cost of new entry ("Net CONE") ISO ELCC data as of April 2025 and representative of annualized ELCC values

1. Firming costs reflect the cost of additional capacity required to supplement the net capacity of the renewable resource (nameplate capacity * (1 – ELCC)) and the 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 peaker as the assumed new resource in MISO ($10 03/kW-mo), SPP ($8 38/kW-mo), PJM ($10 29/kW-mo) and ERCOT ($9 92/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 capacity and 4-hour duration
2. Reflects the average of the high and low of Lazard's LCOE v18 0 for each technology using the regional capacity factor, as indicated, to demonstrate the regional differences in project costs
3. ELCC is an indicator of the incremental reliability contribution of a given resource to the electricity grid 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 by 0 85 MW of additional firm capacity in order to represent the addition of 1 MW of firm system capacity
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 55% to 75% for PJM and CAISO, respectively
5. This sensitivity analysis assumes that projects qualify for the full ITC, have a capital structure that includes sponsor equity, debt and tax equity and assumes the equity owner has taxable income to monetize the tax credits

Appendix

A

LCOE v18.0

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*	*30*
Capacity (MW)	(A)		300	300	300	300	300	300
Capacity Factor	(B)		55%	55%	55%	55%	55%	55%
Total Generation ('000 MWh)	(C)* = (A) x (B)		1,445	1,445	1,445	1,445	1,445	1,445
Levelized Energy Cost ($/MWh)	***(D)***		***$36.7***	***$36.7***	***$36.7***	***$36.7***	***$36.7***	***$36.7***
Total Revenues	**(E)* = (C) x (D)**		**$53.0**	**$53.0**	**$53.0**	**$53.0**	**$53.0**	**$53.0**
Total Fuel Cost	(F)		--	--	--	--	--	--
Total O&M	(G)*		7.4	7.5	7.7	7 9	8.0	14.0
Total Operating Costs	**(H) = (F) + (G)**		**$7.4**	**$7.5**	**$7.7**	**$7.9**	**$8.0**	**$14.0**
EBITDA	**(I) = (E) - (H)**		**$45.7**	**$45.5**	**$45.3**	**$45.1**	**$45.0**	**$39.0**
Debt Outstanding - Beginning of Period	(J)		$342 0 [2]	$339.0	$335.7	$332 2	$328.4	$28.1
Debt - Interest Expense	(K)		(27.4)	(27.1)	(26.9)	(26 6)	(26.3)	(2.3)
Debt - Principal Payment	(L)		(3 0)	(3.3)	(3.5)	(3 8)	(4.1)	(28.1)
Levelized Debt Service	**(M) = (K) + (L)**		**($30.4)**	**($30.4)**	**($30.4)**	**($30.4)**	**($30.4)**	**($30.4)**
EBITDA	(I)		$45.7	$45.5	$45.3	$45.1	$45.0	$39.0
Depreciation (MACRS)	(N)		(114 0)	(182.4)	(109.4)	(65.7)	(65.7)	0.0
Interest Expense	(K)		(27.4)	(27.1)	(26.9)	(26 6)	(26.3)	39.0
Taxable Income	**(O) = (I) + (N) + (K)**		**($95.7)**	**($164.0)**	**($91.0)**	**($47.1)**	**($47.0)**	**($2.3)**
Tax Benefit (Liability) [3]	**(P) = (O) x (tax rate)**		**$38.5**	**$65.9**	**$36.6**	**$18.9**	**$18.9**	**($14.8)**
After-Tax Net Equity Cash Flow	**(Q) = (I) + (M) + (P)**	**($228.0)** [4]	**$53.7**	**$81.0**	**$51.5**	**$33.7**	**$33.5**	**($6.2)**
IRR For Equity Investors		**12%**						

Key Assumptions [5]	
Capacity (MW)	300
Capacity Factor	55%
Fuel Cost ($/MMBtu)	$0.00
Heat Rate (Btu/kWh)	0
Fixed O&M ($/kW-year)	$24 5
Variable O&M ($/MWh)	$0 0
O&M Escalation Rate	2 25%
Capital Structure	
Debt	60.0%
Cost of Debt	8.0%
Equity	40.0%
Cost of Equity	12.0%
Taxes and Tax Incentives:	
Combined Tax Rate	40%
Economic Life (years) [6]	30
MACRS Depreciation (Year Schedule)	5
Capex	
EPC Costs ($/kW)	$1,900
Additional Owner's Costs ($/kW)	$0
Transmission Costs ($/kW)	$0
Total Capital Costs ($/kW)	$1,900
Total Capex ($m)	$570

Technology-Dependent

Consistent Across Versions/Technologies

Source Lazard estimates and publicly available information
Note Numbers presented for illustrative purposes only
* Denotes unit conversion
1 Assumes half-year convention for discounting purposes
2 Reflects initial debt financing to fund capex
3 Assumes full monetization of tax benefits or losses immediately
4 Reflects initial cash outflow from equity investors to fund capex
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 Energy—Key Assumptions

		Renewable Energy: Solar PV					
	Units	Community and C&I			Utility		
		Low		High	Low		High
Net Facility Output	MW		2.0			150	
Total Capital Cost	$/kW	$1,600	–	$3,300	$1,150	–	$1,600
Fixed O&M	$/kW-yr	$13.00	–	$20.00	$11.00	–	$14.00
Variable O&M	$/MWh		—			—	
Heat Rate	Btu/kWh		—			—	
Capacity Factor	%	20%	–	15%	30%	–	20%
Fuel Price	$/MMBTU		—			—	
Construction Time	Months		6			15	
Facility Life	Years		30			35	
Levelized Cost of Energy	$/MWh	$81	–	$217	$38	–	$78

Source Lazard estimates and publicly available information

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

		Renewable Energy					
	Units	Geothermal		Wind—Onshore		Wind—Offshore	
		Low	High	Low	High	Low	High
Net Facility Output	MW	250		300		900	
Total Capital Cost	$/kW	$5,000	$6,460	$1,900	$2,300	$3,450	$6,550
Fixed O&M	$/kW-yr	$14.50	$15.75	$24.50	$40.00	$60.00	$91.50
Variable O&M	$/MWh	$9.05	$24.80	—		—	
Heat Rate	Btu/kWh	—		—		—	
Capacity Factor	%	90%	80%	55%	30%	55%	45%
Fuel Price	$/MMBTU	—		—		—	
Construction Time	Months	36		18		24	
Facility Life	Years	25		30		30	
Levelized Cost of Energy	$/MWh	$66	$109	$37	$86	$70	$157

Source Lazard estimates and publicly available information

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

	Units	Renewable Energy: Hybrid Generation + Storage					
		Solar PV + Storage—Utility			Wind + Storage—Onshore		
		Low		High	Low		High
Storage							
Power Rating	MW		50			50	
Duration	Hours		4			4	
Usable Energy	MWh		200			200	
90% Depth of Discharge Cycles/Year	%		350			350	
Roundtrip Efficiency	%		92%			92%	
Inverter Cost	$/kW	$19	–	$50	$19	–	$50
Total Capital Cost (excl. Inverter)	$/kWh	$122	–	$313	$122	–	$313
Storage O&M	$/kWh	$3.00	–	$8.02	$3.00	–	$8.02
Generation							
Capacity	MW		100			100	
Capacity Factor	%	30.0%	–	20.0%	55.0%	–	30.0%
Project Life	Years		35			30	
Total Capital Cost	$/kW	$1,150	–	$1,600	$1,900	–	$2,300
Fixed O&M	$/kW	$11.00	–	$14.00	$24.50	–	$40.00
Extended Warranty Start	Year		3			3	
Warranty Expense % of Capital Costs	%	0.7%	–	1.9%	0.7%	–	1.9%
Charging Cost	$/MWh		$0.00			$0.00	
Unsubsidized LCOE	$/MWh	$50	–	$131	$44	–	$123

Source Lazard estimates and publicly available information
Note Hybrid scenarios assume 10% cost synergies for storage capital costs and 25% synergies for inverter costs due to colocation of the storage and generation asset

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

	Units	Conventional Energy							
		Gas Peaking (New Build)		U.S. Nuclear (New Build)		Coal (New Build)		Gas Combined Cycle (New Build)	
		Low	High	Low	High	Low	High	Low	High
Net Facility Output	MW	550	175	2,200		600		1,225	750
Total Capital Cost	$/kW	$1,150	$1,450	$9,020	$14,820	$3,405	$7,210	$1,200	$1,600
Fixed O&M	$/kW-yr	$10.00	$17.00	$136.00	$158.00	$40.85	$94.35	$10.00	$25.50
Variable O&M	$/MWh	$3.50	$5.00	$4.40	$5.15	$3.10	$5.70	$2.75	$5.00
Heat Rate	Btu/kWh	10,275	11,175	10,450		8,750	12,000	6,475	6,550
Capacity Factor	%	15%	10%	92%	89%	85%	65%	90%	30%
Fuel Price	$/MMBTU	$3.45		$0.85		$1.47		$3.45	
Construction Time	Months	24		84		60	66	24	
Facility Life	Years	30		70		40		30	
Levelized Cost of Energy	$/MWh	$149	$251	$141	$220	$71	$173	$48	$109

Source Lazard estimates and publicly available information

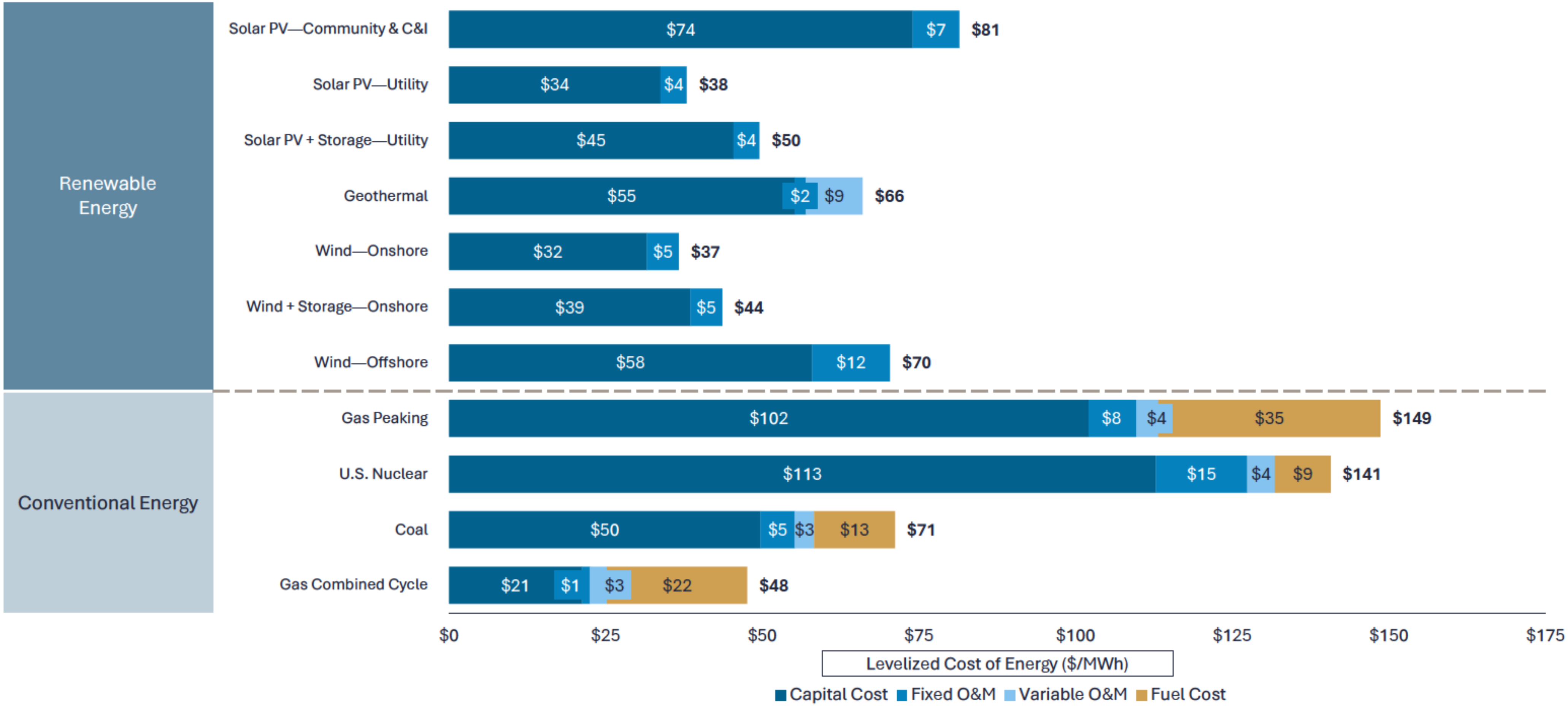
Levelized Cost of Energy—Key Assumptions (cont'd)

		Marginal Cost of Selected Existing Conventional Generation							
	Units	Gas Peaking (Operating)		U.S. Nuclear (Operating)		Coal (Operating)		Gas Combined Cycle (Operating)	
		Low	High	Low	High	Low	High	Low	High
Net Facility Output	MW	240 –	50	2,200		600		550	
Total Capital Cost	$/kW	$0		$0		$0		$0	
Fixed O&M	$/kW-yr	$4.00 –	$6.10	$89.00 –	$121.60	$21.70 –	$33.80	$8.90 –	$13.60
Variable O&M	$/MWh	$2.70 –	$9.30	$2.70 –	$3.90	$3.20 –	$7.20	$0.80 –	$1.80
Heat Rate	Btu/kWh	10,900 –	12,550	10,400 –	10,400	10,250 –	11,800	6,950 –	7,475
Capacity Factor	%	5% –	1%	91% –	87%	49% –	7%	62% –	17%
Fuel Price	$/MMBtu	$2.50 –	$2.90	$0.80 –	$0.80	$1.70 –	$2.40	$2.50 –	$2.90
Construction Time	Months	24		84		60		24	
Facility Life	Years	30		70		40		30	
Levelized Cost of Energy	$/MWh	$47 –	$170	$30 –	$38	$31 –	$114	$24 –	$39

Source Lazard estimates and publicly available information

Levelized Cost of Energy Components—Low End ($/MWh)

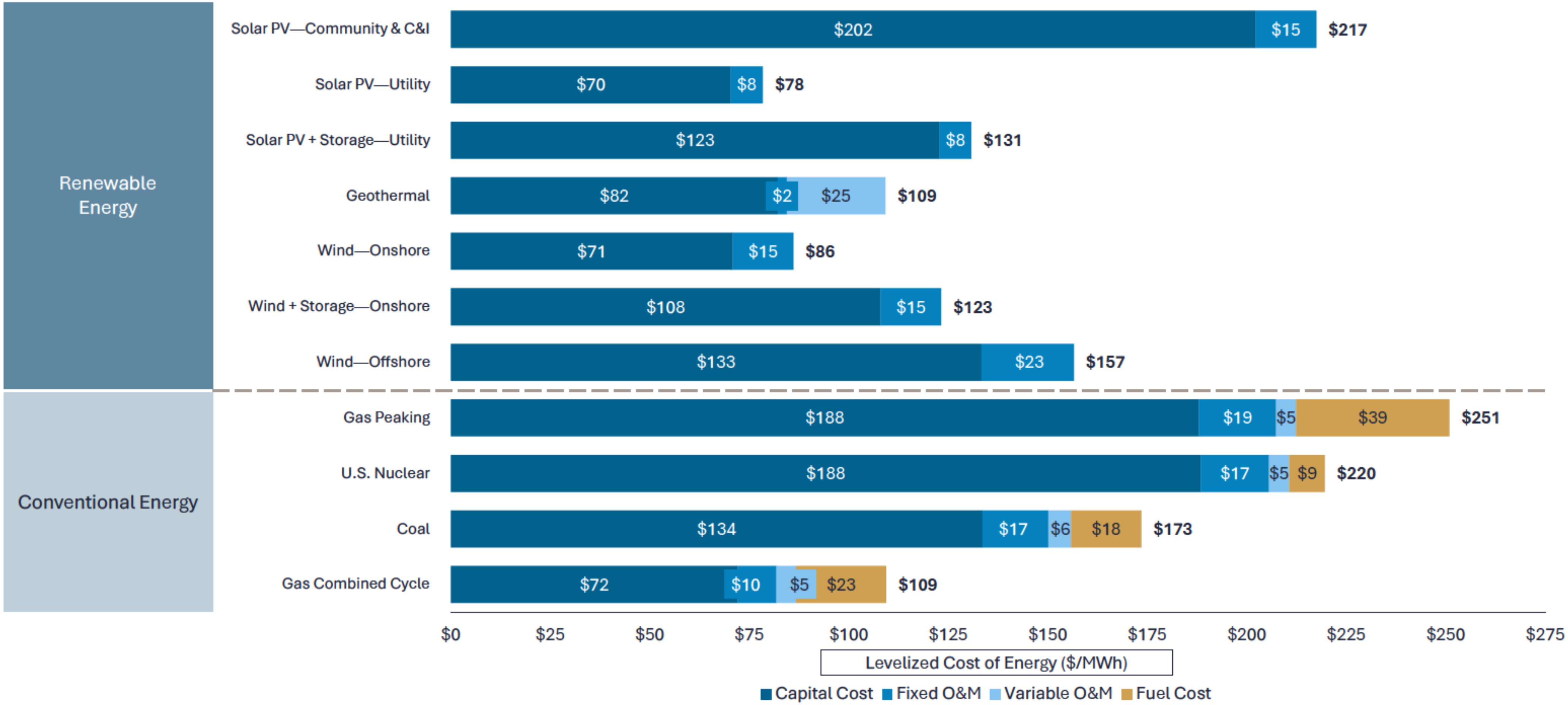
Certain renewable energy generation technologies are already cost-competitive with conventional generation technologies; key factors regarding the continued cost decline of renewable energy generation technologies are the ability of technological development and Industry scale to continue lowering operating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



Source Lazard estimates and publicly available information
Note Figures may not sum due to rounding

Levelized Cost of Energy Components—High End ($/MWh)

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 estimates and publicly available information
Note Figures may not sum due to rounding

B LCOS v10.0

Levelized Cost of Storage Comparison—Methodology

($ in millions, unless otherwise noted)

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" page for detailed assumptions by technology)

Subsidized Utility-Scale Standalone (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	107	104	102	110	110
Total Generation ('000 MWh)[2]	(B)*		63	63	63	63	63	63
Levelized Storage Cost ($/MWh)	***(C)***		***$95***	***$95***	***$95***	***$95***	***$95***	***$95***
Total Revenues	**(D)* = (B) x (C)**		**$6.0**	**$6.0**	**$6.0**	**$6.0**	**$6.0**	**$6.0**
Total Charging Cost[3]	(E)		(2.3)	(2.3)	(2.4)	(2.4)	(2 5)	(3.3)
Total O&M, Warranty, & Augmentation[4]	(F)*		(0.6)	(0.6)	(0.8)	(0 8)	(2 6)	(1.1)
Total Operating Costs	**(G) = (E) + (F)**		**($2.9)**	**($2.9)**	**($3.2)**	**($3 3)**	**($5.1)**	**($4.5)**
EBITDA	**(H) = (D) - (G)**		**$3.1**	**$3.0**	**$2.8**	**$2.7**	**$0.9**	**$1.5**
Debt Outstanding - Beginning of Period	(I)		$6.8[5]	$6.6	$6.4	$6 3	$6.1	$0.6
Debt - Interest Expense	(J)		(0.5)	(0.5)	(0.5)	(0 5)	(0 5)	(0.1)
Debt - Principal Payment	(K)		(0.1)	(0.2)	(0.2)	(0 2)	(0 2)	(0.6)
Levelized Debt Service	**(L) = (J) + (K)**		**(0.7)**	**(0.7)**	**(0.7)**	**(0.7)**	**(0.7)**	**(0.7)**
EBITDA	(H)		$3.1	$3.0	$2.8	$2.7	$0 9	$1.5
Depreciation (MACRS)	(M)		(5.4)	(8.6)	(5.2)	(3.1)	(3.1)	0.0
Interest Expense	(J)		(0.5)	1.7	0.0	0 0	0 0	(0.5)
Taxable Income	**(N) = (H) + (M) + (J)**		**($2.9)**	**($3.9)**	**($2.4)**	**($0.4)**	**($2.2)**	**$1.1**
Tax Benefit (Liability)	**(O) = (N) x (Tax Rate)**		**$1.2**	**$1.6**	**$1.0**	**$0.2**	**$0.9**	**($0.4)**
Federal Investment Tax Credit (ITC)	**(P)**		**$13.5**	**$0.0**	**$0.0**	**$0.0**	**$0.0**	**$0.0**
After-Tax Net Equity Cash Flow	**(Q) = (H) + (L) + (O) + (P)**	**($27.0)**[6]	**$17.0**	**$3.9**	**$3.1**	**$2.2**	**$1.1**	**$0.4**
IRR For Equity Investors		**12.0%**						

Key Assumptions[7]	
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)	$0 033
Fixed O&M Cost ($/kWh)	$3.00
Fixed O&M Escalator (%)	2.5%
Charging Cost Escalator (%)	1 97%
Efficiency (%)	91%
Capital Structure	
Debt	20.0%
Cost of Debt	8.0%
Equity	80.0%
Cost of Equity	12.0%
Taxes	
Combined Tax Rate	40.2%
Economic Life (years)	20
MACRS (Year Schedule)	5 Years
Federal ITC - BESS	40%
Capex	
Total Initial Installed Cost ($/kWh)[8]	$153
Extended Warranty (% of Capital Cost)	0.7%
Extended Warranty Start Year	3
Total Capex ($m)	$34

Technology-Dependent

Consistent Across Versions/Technologies

Source: Lazard estimates and publicly available information
Note: Numbers 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 (BESS 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 starting in year 3
5 Reflects initial debt financing to fund capex
6 Reflects initial cash outflow from equity sponsor
7 Reflects a "key" subset of all assumptions for methodology and illustration purposes only Does not reflect all assumptions
8 Initial Installed Cost includes inverter cost, module cost, balance-of-system cost and EPC cost

Levelized Cost of Storage—Key Assumptions

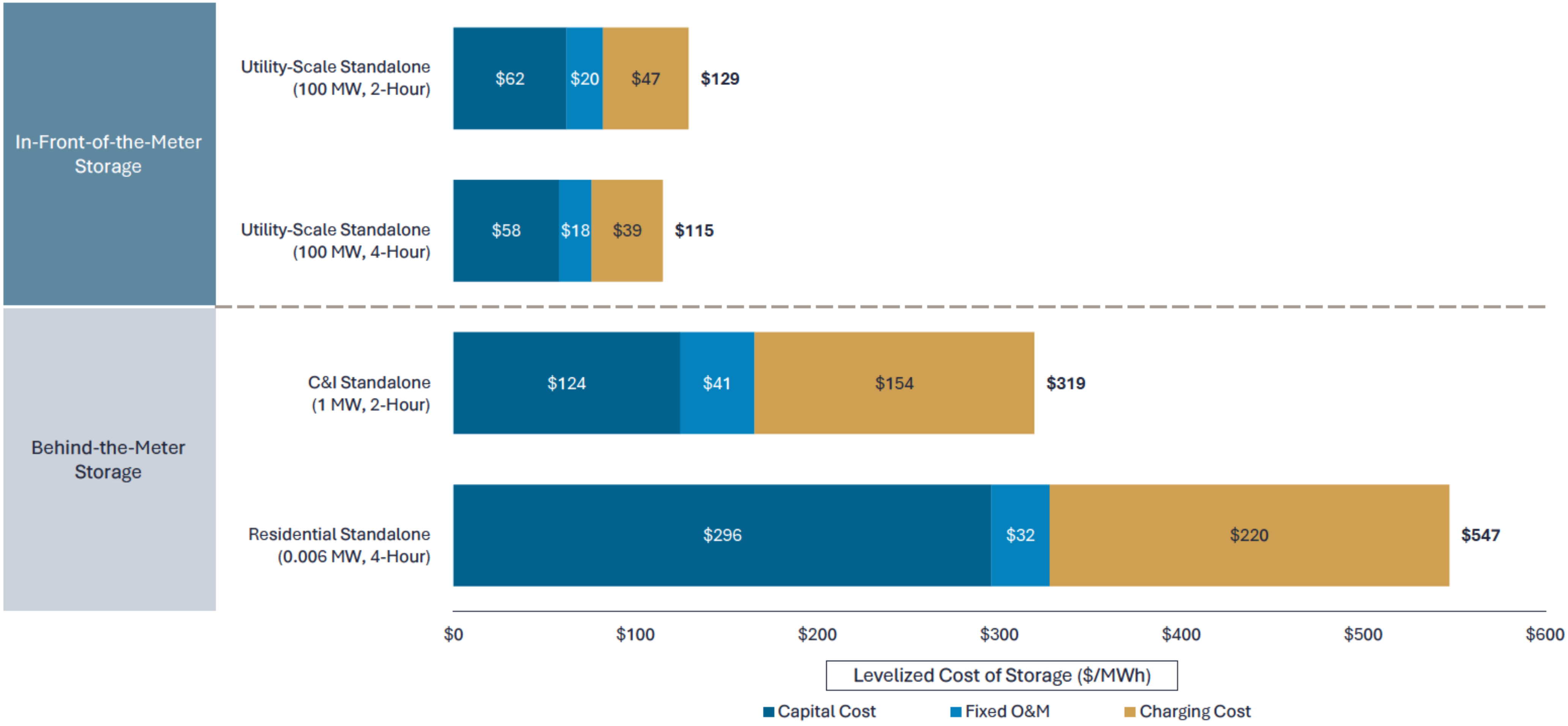
	Units	Utility-Scale Standalone (100 MW/200 MWh)	Utility-Scale Standalone (100 MW/400 MWh)	C&I Standalone (1 MW/2 MWh)	Residential Standalone (0.006 MW/0.025 MWh)
Power Rating	MW	100	100	1	0.006
Duration	Hours	2.0	4.0	2.0	4.2
Usable Energy	MWh	200	400	2	0.025
90% Depth of Discharge Cycles/Day	#	1	1	1	1
Operating Days/Year	#	350	350	350	350
Solar/Wind Capacity	MW	0.00	0.00	0.00	0.000
Annual Solar/Wind Generation	MWh	0	0	0	0
Project Life	Years	20	20	20	20
Annual Storage Output	MWh	63,000	126,000	630	8
Lifetime Storage Output	MWh	1,260,000	2,520,000	12,600	158
Initial Capital Cost—DC	$/kWh	$113 – $244	$107 – $232	$238 – $445	$721 – $1,338
Initial Capital Cost—AC	$/kW	$26 – $70	$25 – $67	$40 – $80	$0 – $0
EPC Costs	$/kWh	$29 – $122	$28 – $116	$56 – $168	$0 – $0
Solar/Wind Capital Cost	$/kW	$0 – $0	$0 – $0	$0 – $0	$0 – $0
Total Initial Installed Cost	M $	$34 – $88	$62 – $160	$1 – $1	$0 – $0
Storage O&M	$/kWh	$3.0 – $8.2	$3.0 – $8.0	$7.3 – $9.1	$0.0 – $0.0
Extended Warranty Start	Year	3	3	3	3
Warranty Expense % of Capital Costs	%	0.65% – 1.50%	0.66% – 1.85%	0.50% – 1.30%	0.00% – 0.00%
Investment Tax Credit (Solar)	%	0%	0%	0%	0%
Investment Tax Credit (Storage)	%	30.00% – 40.00%	30.00% – 40.00%	30.00% – 40.00%	30.00% – 40.00%
Production Tax Credit	$/MWh	$0	$0	$0	$0
Charging Cost	$/MWh	$33	$27	$111	$152
Charging Cost Escalator	%	1.97%	1.97%	1.97%	1.97%
Efficiency of Storage Technology	%	91% – 87%	92% – 86%	92% – 88%	91% – 88%
Unsubsidized LCOS	$/MWh	$129 – $277	$115 – $254	$319 – $506	$547 – $860

Source Lazard estimates and publicly available information

Note All cases were modeled using 90% depth of discharge and 10% overbuild 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)"

Levelized Cost of Storage Components—Low End ($/MWh)

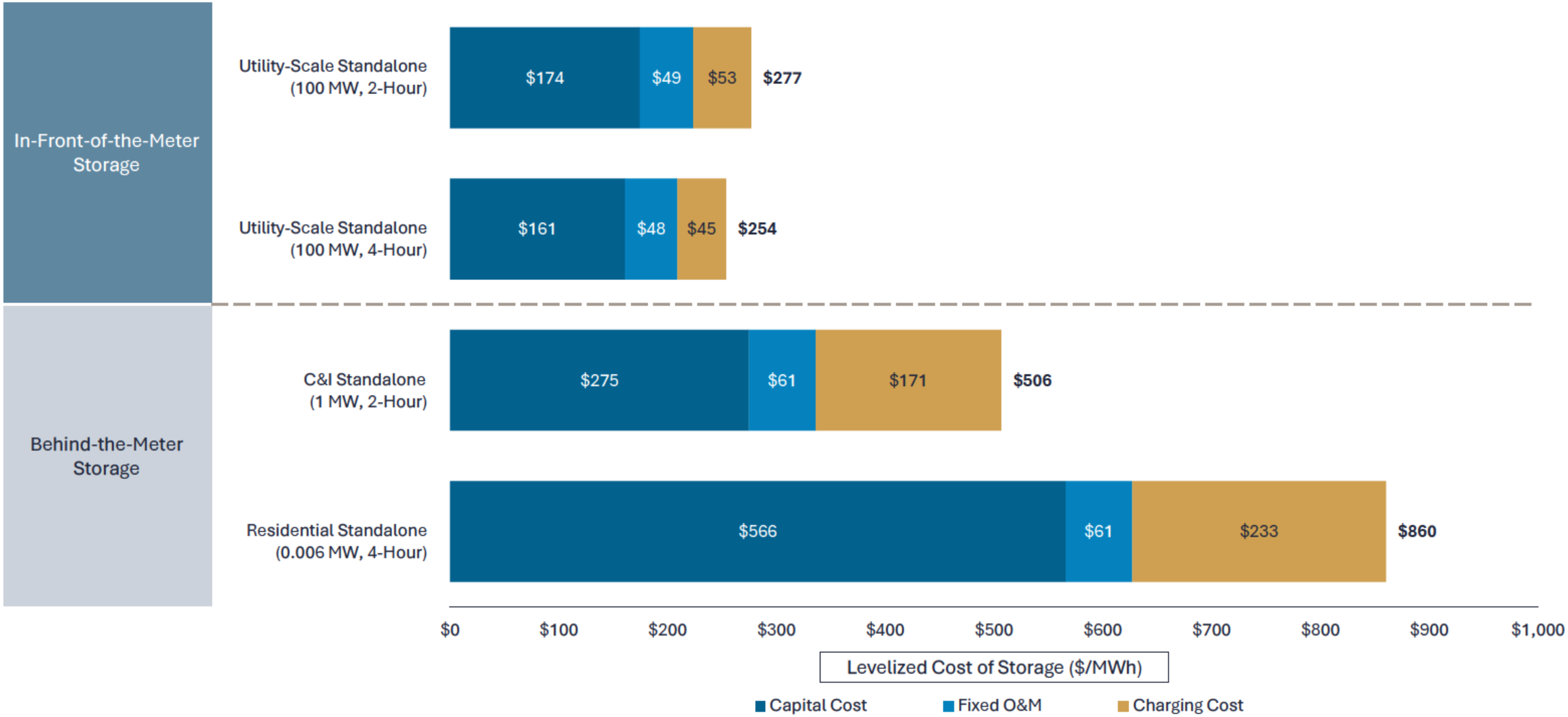
Capital costs, fixed operating costs and charging costs contribute to the all-in cost in varying proportions depending on the specific energy storage use case and configuration



Source Lazard estimates and publicly available information
Note Figures may not sum due to rounding

Levelized Cost of Storage Components—High End ($/MWh)

Capital costs, fixed operating costs and charging costs contribute to the all-in cost in varying proportions depending on the specific energy storage use case and configuration



Source Lazard estimates and publicly available information
Note Figures may not sum due to rounding

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 Storage	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 analysis analyzes 2- and 4-hour durations[2]	• Lithium Iron Phosphate (LFP) • Lithium Nickel Manganese Cobalt Oxide (NMC)
Behind-the-Meter Storage	Commercial & Industrial Standalone	• Energy storage system designed for behind-the-meter peak shaving and demand charge reduction for C&I users – Units are 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)
	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)

Source Lazard 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 Case Studies only evaluate 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

		(A) Project Life (Years)	(B) Storage (MW)[2]	Solar/ Wind (MW)	Battery Degradation (per annum)	(C) Storage Duration (Hours)	B x C = (D) Nameplate Capacity (MWh)[3]	(E) 90% DOD Cycles/ Day[4]	(F) Days/ Year[5]	D x E x F = (G) Annual MWh[6]	A x G = (H) Project MWh
In-Front-of-the-Meter Storage	Utility-Scale Standalone	20	100	–	2.6%	2	200	1	350	63,000	1,260,000
		20	100	–	2.6%	4	400	1	350	126,000	2,520,000
Behind-the-Meter Storage	Commercial & Industrial Standalone	20	1	–	2.6%	2	2	1	350	630	12,600
	Residential Standalone	20	0.006	–	1.9%	4	0.025	1	350	8	158

[dashed box] = "Usable Energy"[7]

Source Lazard 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 Indicates power rating of system (i e , system size)

3 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)

4 "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

5 Indicates number of days of system operation per calendar year

6 Augmented to nameplate MWh capacity as needed to ensure usable energy is maintained at the nameplate capacity, based on Year 1 storage module cost

7 Usable energy indicates energy stored and available to be dispatched from the battery

LAZARD LCOE+

Lazard's LCOE+ will continue to evolve over time, and we appreciate that there can, and will be, varied views regarding the specifics of our analyses. Accordingly, we would be happy to discuss any of our underlying assumptions and analyses in further detail—and, to be clear, we welcome these discussions as we try to improve our studies over time. In that regard, the studies remain our attempt to contribute in a differentiated and impactful manner to the Industry.

More generally, Lazard remains committed to our Power, Energy & Infrastructure Group clients, who remain our highest priority. In that regard, we believe that we have the greatest allocation of resources and effort devoted to this sector of any investment bank. Further, we have an ongoing and intense focus on strategic issues that require long-term commitment and planning. Accordingly, Lazard strives to maintain its preeminent position as a thought leader and leading advisor to clients on their most important matters, especially in this Industry.

If you have any questions regarding this memorandum or Lazard's LCOE+, please feel free to contact any member of the Lazard Power, Energy & Infrastructure Group, including those listed below.

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Renewable energy remains cheapest power builds as new gas plants get pricier

By Reuters

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A sheep moves across a solar farm in Haskell, Texas, U.S. December 2, 2024. REUTERS/Annie Rice/File photo Purchase Licensing Rights

NEW YORK, June 16 (Reuters) - Renewable power like solar and onshore wind is the least expensive and quickest power generation source to deploy in the United States, even without government subsidies, Lazard said in a report on Monday.

The cost to build new gas-fired power plants, meanwhile, has hit a 10-year high amidst the country's record electricity use and growing backlogs for turbines and other equipment needed to construct the plants, Lazard, a global financial services firm, said in its annual Levelized Cost of Energy+ analysis.

WHY IT MATTERS

As U.S. electricity use rises from the expansion energy-intensive data centers and the electrification of industries like transportation, many new power plants will need to be built to meet the rising demand after a nearly 20-year lull.

A shift in support of fossil-fired power like coal and gas, over the renewable energy championed by former President Joe Biden, has raised questions about what types of electricity-generating sources will rise to meet the growing demand.

Different power-producing sources have varying implications for the reliability of the electric grid and for climate change.

BY THE NUMBERS

The cost to build a utility-scale solar farm ranged from $38 to $78 per megawatt hour, while costs for natural gas combined cycle plants were $48 to $107 per megawatt hour. Smaller-scale community solar and gas peaker plants, meanwhile, were considerably more expensive.

Reporting by Laila Kearney; Editing by Mark Porter

E&E NEWS By POLITICO

Pipeline enforcement plunges in Trump's first months

By Mike Soraghan

05/12/2025 07:23 AM EDT

Federal pipeline safety enforcement has fallen to unprecedented lows in the first few months of the Trump administration.

No enforcement actions were launched in March, the first time in the 20-year history of the Pipeline and Hazardous Materials Safety Administration that no cases were initiated in a month. Before that, only one case was initiated in February.

The tally inched up in April, with four cases.

Those numbers are from a brief period of time. Still, the steepness of the drop raises questions about whether the Trump administration's fervor to shrink government intervention could also mean diminished enforcement of existing safety standards.

But PHMSA officials argue that's not a sign the agency will be less aggressive under President Donald Trump, saying their commitment to enforcement shouldn't be judged by the first three months of a new administration.

"Enforcement numbers from the beginning of an administration as a new team transitions are not indicative of long-term trends or a lack of commitment to enforcement," said PHMSA spokesperson Emily Wong.

But enforcement doesn't always drop during presidential transitions. In the first three months of Trump's first term in 2017, PHMSA filed 66 cases.

Wong also said the agency has recently closed three cases with "significant civil penalties." That would include a $1.5 million fine paid by Freeport LNG from an explosion at its terminal south of Houston in June 2022. And the agency responded to two high-profile leaks, one on the Keystone oil pipeline in North Dakota and the other on a fuel line in Bucks County, Pennsylvania.

Case closure numbers have been robust in recent months, but not at record-breaking levels. PHMSA closed 26 cases in March and 13 in April. In the past, the agency has closed as many as 61 cases in one month: September 2010. The Biden administration closed seven cases last July and 12 in December.

On average, PHMSA initiates about 18 cases per month. In Trump's first term, it averaged a little less than that. During the Biden administration, the average was slightly higher. Since PHMSA was established in November 2004, the most enforcement actions issued in a month was 65. Until this year, PHMSA had never issued fewer than three enforcement actions in a month.

There could be other explanations for the decline, though agency officials did not offer them as reasons.

The Trump administration has been aggressively culling the federal workforce with layoffs, firings and incentives to leave. Administration officials have said that employees in critical safety roles, such as inspectors and investigators, will be retained. But there are no official numbers on how many people left PHMSA, which had about 600 employees before the cutbacks began. And there's no public data on whether all safety-critical employees have remained.

But the senior career leadership at PHMSA was largely cleared out, including the top career pipeline safety official, Alan Mayberry. He's one of at least eight career leaders who have left since Trump returned to the White House or are expected to leave.

Trump has nominated Paul Roberti, general counsel to PHMSA in his first term, to lead the agency as administrator. The role requires confirmation by the Senate, which has taken no action on Roberti.

The wait for a new administrator could be part of the slowdown, said Joseph Hainline, who was a PHMSA attorney before and during Roberti's tenure.

"I think you'll see it pick up as they get fully staffed once Paul gets there," said Hainline, now a partner at the Van Ness Feldman firm. "I think the first couple months are always sorting through the priorities, dealing with all of the top down changes from the administration."

The agency is currently being run by Deputy Administrator Ben Kochman, formerly director of pipeline safety policy at the Interstate Natural Gas Association of America (INGAA). At PHMSA, he is serving as acting administrator. The chief counsel is Keith Coyle, a former PHMSA staff attorney who represented pipeline companies in private practice before his appointment.

Former President Joe Biden never named a full-time PHMSA administrator during his four years in office.

Whatever the reason, the recent decline in enforcement is concerning, said Bill Caram, executive director of the Pipeline Safety Trust, the country's main pipeline safety advocacy group. It also raises questions about whether the agency is adequately overseeing safety, he said in an email.

"Regular, consistent enforcement helps keep our communities and the environment safe from the risks of pipelines," Caram said, "and substantial drops from established enforcement levels deserves our close attention."

The White House did not respond to a request for comment last week. Freeport LNG declined to comment.

Keystone operator South Bow responded to a request for comment by pointing to the incident webpage for the leak. Energy Transfer, which operates the pipeline that leaked in Pennsylvania, didn't respond to a request for comment. But one industry leader said statistics don't always show the full breadth of an administration's approach to enforcement.

"While any administration can juice the numbers if they want with ticky-tack enforcement actions, we hope this administration will make a difference with an enforcement program that focuses on what is really meaningful for pipeline safety," Andy Black, CEO of the Liquid Energy Pipeline Association, said in an emailed statement.

Pipelines are an important symbol of Trump's energy agenda. One of his first acts as president in his first term was to boost two oil pipeline projects loathed by environmentalists and left-leaning groups: Keystone XL and Dakota Access.

Trump's top oil and gas donor in last year's presidential election was pipeline mogul Kelcy Warren, the executive chair of Energy Transfer, which developed Dakota Access. Warren put $12.5 million, from personal funds and a company in which he has controlling interest, toward getting Trump back to the White House. Shortly after Trump took office, Energy Transfer challenged PHMSA's in-house regulatory system in court as "unconstitutional."

Pipeline safety enforcement civil penalties shot up after Biden succeeded Trump in 2017.

And during Biden's term, pipelines became an increasingly contentious part of the debate over climate change as the agency drafted a regulation to crack down on natural gas emissions from pipes and other energy infrastructure. PHMSA finished the rule in the final days of Biden's term, but the Trump administration hasn't implemented it and isn't expected to do so.

When asked about the scarcity of enforcement actions, INGAA — which represents operators of interstate gas transmission lines — stressed the industry's commitment to safety.

"Safety is at the forefront of everything our members do, and our collective goal is zero incidents," Amy Andryszak, the group's CEO, said in an emailed statement. "This laser-like focus on safety and compliance should result in fewer enforcement actions."

The American Petroleum Institute, a major U.S. oil and gas trade group, said in an emailed statement that the industry "remains committed to working with PHMSA to advance the safe and responsible operation of essential pipeline infrastructure that delivers affordable, reliable energy to Americans across the country."