BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

LC 80

In the Matter of PORTLAND GENERAL ELECTRIC CO., 2023 Integrated Resource Plan and Clean Energy Plan.	INITIAL COMMENTS OF THE SWAN LAKE AND GOLDENDALE ENERGY STORAGE PROJECTS ON PORTLAND GENERAL ELECTRIC CO.'s 2023 CLEAN ENERGY PLAN AND INTEGRATED RESOURCE PLAN

The companies working to develop the Swan Lake and Goldendale pumped storage projects ("Swan Lake and Goldendale" or "Projects") appreciate Portland General Electric Company's ("PGE") work that went into preparing its 2023 Integrated Resource Plan and Clean Energy Plan ("IRP"), which was filed in the above-referenced proceeding on March 31, 2023. The assigned Administrative Law Judge of the Oregon Public Utility Commission ("Commission") issued a memorandum on April 20, 2023, adopting the procedural schedule for this proceeding (the "Scheduling Memorandum").[1] The Scheduling Memorandum set May 4, 2023 as the deadline for Initial Staff and Stakeholder Comments. In accordance with the deadlines established in the Scheduling Memorandum, Swan Lake and Goldendale are filing these initial comments as intervenors in this proceeding.

[1] *In the Matter of Portland General Electric Co., 2023 Clean Energy Plan and Integrated Resource Plan*, Memorandum, Docket LC 80 (April 20, 2023), available at: http://edocs.puc.state.or.us/efdocs/HDA/lc80hda155619.pdf (PGE IRP).

I. Introduction.

Swan Lake and Goldendale are two closed-loop pumped storage projects, one of which is located in the State of Oregon. The Projects are actively engaged with various offtakers, including utilities in Oregon that are subject to the Commission's regulation. As a result, Swan Lake and Goldendale have an interest in how PGE's IRP appropriately considers, and fairly evaluates, energy storage projects, including pumped storage.

Swan Lake and Goldendale have concerns regarding how pumped storage is evaluated in PGE's IRP. Specifically, Swan Lake and Goldendale are concerned that: (1) pumped storage is not appropriately considered in the IRP; (2) pumped storage has major benefits for the transmission needs identified in the IRP, and those benefits are not being adequately considered; and (3) PGE should consider pumped storage as a complementary way to meet its capacity and storage needs while also creating technology and duration diversity. Furthermore, the Projects suggest that PGE's analysis—particularly by relying solely on significant battery additions over the IRP planning horizon—may give rise to feasibility challenges.

II. Pumped Storage is Not Appropriately Considered in PGE's 2023 IRP And Should Be Corrected In PGE's Update on May 31, 2023.

The Projects seek to point that that the IRP may miscategorize or ignore pumped storage throughout the IRP, which may unnecessarily disadvantage pumped storage relative to other storage resources.

First, PGE lists pumped storage as an "emerging technology" in its portfolio analysis and seems to exclude pumped storage from consideration in the portfolio analysis. There is strong historical data and current use cases that demonstrate pumped storage is not an emerging technology—rather, that it is a mature technology with a robust operational history, meaning, at minimum, pumped storage should be fairly considered and compared in the IRP with all other storage resources. Categorizing pumped storage as an "emerging technology," and excluding it from consideration in the Preferred Portfolio appears to be inconsistent with the Commission's IRP Guidelines that state PGE must fairly consider all resource types.[2]

Second, pumped storage appears to be unnecessarily disadvantaged due to what may be erroneous assumptions throughout the IRP document, which is unlike PGE's 2019 IRP, where PGE's model considered pumped storage in a way that was exemplary for the region.[3] Swan Lake and Goldendale urge PGE to update its consideration of pumped storage throughout the IRP for its IRP Update, which is due to the Commission by May 31, 2023, according to the Scheduling Memorandum. PGE's analysis may benefit from taking into consideration more updated information regarding the capabilities and costs of pumped storage systems. `

a. Pumped storage is not an "emerging technology" and listing it as such may violate the Commission's IRP Guidelines pertaining to fairly comparing resources.

PGE's IRP lists pumped storage as an "emerging technology" in the "emerging technology portfolios" section of the IRP.[4] It seems that by including pumped storage in this category, pumped storage is excluded from selection in the Preferred Portfolio. Pumped storage is not an "emerging technology"—the first known cases of pumped storage were in Italy and Switzerland in the 1890s,

[2] *In the Matter of Public Utility Commission of Oregon, Investigation Into Integrated Resource Planning*, Order No. 07-002, Docket No. UM 1056 (January 8, 2007) (*Commission IRP Guidelines*), Guideline 1a, Guideline 4h, Guideline 4l; *see also* PGE IRP, Chapter 11, Table 64 at page 289 (showing the selection of 4-hour Li-ion batteries as the only stand-alone storage in the Preferred Portfolio).

[3] *In the Matter of Portland General Electric Co., 2019 Integrated Resource Plan*, Comments of Swan Lake North Pumped storage LLC and the Goldendale Energy Storage Project, Docket LC 73 (April 12, 2021) at 2.

[4] *In the Matter of Portland General Electric Co., 2023 Clean Energy Plan and Integrated Resource Plan*, 2023 Clean Energy Plan and Integrated Resource Plan, Docket LC 80 (March 31, 2023), available at: https://apps.puc.state.or.us/edockets/edocs.asp?FileType=HAA&FileName=lc80haa8431.pdf&DocketID=23636&numSequence=14.

and it was first used in the United States in 1930.[5] According to the 2021 Department of Energy Hydropower Report, pumped storage contributes to 93% of grid storage in the United States and is growing nearly as fast as all other storage technologies combined.[6] For example, as of 2021, forty-three pumped storage plants with a total power capacity of 21.9 GW and an estimated energy storage capacity of 553 GWh accounted for 93% of utility-scale storage power capacity and more than 99% of electrical energy storage in 2019.[7] Additionally, 52 GW of *new* pumped storage is in the project development pipeline in the U.S., and over 50 GW is *currently* under construction worldwide.[8] There is abundant evidence to support that utilities have been, and are continuing to use, pumped storage as a core part of their storage portfolios, which demonstrates that pumped storage is not an "emerging technology".

Classifying pumped storage as an "emerging technology" is inconsistent with the Commission's IRP guidelines that state PGE must evaluate resources "on a consistent and comparable basis . . . [a]ll known resources for meeting the utility's load should be considered, including supply-side options which focus on . . . storage . . . ."[9] The Projects interpret this classification to mean that PGE excluded pumped storage as a comparable storage resource in the evaluation of its Preferred Portfolio even though it is required to include it under the IRP Guidelines. PGE must fairly consider all resource types, and pumped storage being inaccurately

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[5] *U.S. Hydropower Market Report*, U.S. Department of Energy (January 2021), available at: https://www.energy.gov/eere/water/pumped-storage-hydropower.

[6] *Id*. at page iv.

[7] *Id*.

[8] *Id*.

[9] *Commission IRP Guidelines*, Guideline 1(a).

categorized as an "emerging technology" appears to result in discriminatory treatment in this IRP, particularly when compared with less proven technologies such as batteries.

To be in accordance with the Commission's IRP Guidelines, Swan Lake and Goldendale request that PGE remove pumped storage from the "emerging technologies" classification and re-analyze its Preferred Portfolio, fairly comparing pumped storage to other storage resources.

b. PGE either leaves out, or relies on incorrect assumptions for, pumped storage throughout the IRP.

Swan Lake and Goldendale request that PGE either address or correct the following in its IRP Update and re-analyze its Preferred Portfolio:

1. Pumped storage is excluded from the entirety of Appendix K, Tuned System ELCCs, and should be included.

2. Pumped storage is excluded from two sections of Chapter 10, Resource Economics, Section 10.5 (Resource capacity contribution) and Section 10.6 (Capacity value) and should be included because pumped storage is a capacity resource. Additionally, PGE needs to clarify whether pumped storage is being considered at all in the discussion of capacity value in Section 10.6.

3. Pumped storage is assigned an "owners cost allowance" in Appendix M, Section M.3.3, Table 159. PGE does not assign an "owners cost allowance" to any other resource type. Additionally, PGE should consider updating the information used to populate the figures for pumped storage in Table 159 as they may be erroneous or outdated.

4. Swan Lake and Goldendale suggest that PGE consider updating the information on pumped storage that is included in the LUCAS tool in Appendix H, Section H.5 as it may be inaccurate.

5. Swan Lake and Goldendale request that PGE consider whether it is correct to assume pumped storage has a greater rate of decline in ELCC value in the winter in Appendix J, Figures 147 and 148. PGE should clarify and correct, if necessary.

Swan Lake and Goldendale respectfully request that PGE re-assess pumped storage as part of an updated portfolio analysis and address and/or correct the issues outlined above in its IRP Update.

III. <u>Pumped Storage Has Major Benefits to the Transmission Needs Identified in the IRP that Should be Considered in the IRP.</u>

PGE's IRP identifies the need to evolve PGE's transmission portfolio to meet decarbonization goals in a reliable manner, expand its reach throughout the West, and strengthen PGE's ability to serve its service territory.[10] Additionally, the decarbonization requirements of Oregon House Bill 2021 require a significant addition to load – PGE has identified "a need for 905 megawatt average (MWa) of GHG-free energy and 1136 megawatts (MW) of summer capacity to reach the 2030 target and maintain system adequacy."[11] In this IRP, PGE has identified that it needs to proactively address solutions to transmission capacity to serve its future load obligations.[12] Swan Lake and Goldendale also identified this need – including pumped storage as

[10] PGE IRP, Chapter 9, Section 9.1 page 207.

[11] *Id*. at page 210, Section 9.1.1.

[12] *Id*. at 211.

one of those solutions – in PGE's 2019 IRP.[13] Swan Lake and Goldendale are glad that PGE has addressed the magnitude and timing of transmission needs – in fact, a key finding of the preferred portfolio is that "additional transmission capacity is the largest factor that influences resource additions and the cost and risk metrics of portfolios" for this IRP.[14] Pumped storage is not currently considered as a capacity resource to increase transmission capacity in the short and long term. Given the substantial capacity benefits that pumped storage can provide to both existing and new transmission compared to the transmission needs in this IRP that are critical to PGE meeting both load and decarbonization mandates, PGE should consider pumped storage in its transmission needs analysis in its IRP Update.

While Swan Lake and Goldendale agree that the solutions PGE identifies in this IRP are possible, including the Big Eddy to Chemawa and Bethel to Round Butte 230kV upgrades, the Projects believe that the magnitude of PGE's transmission expansion is likely not going to be finished by the 2030 date due to construction and land use concerns. Additionally, simply building transmission without evaluating all options to deliver capacity from shovel-ready projects to its system in the near-term (before 2030) has a large impact on ratepayers that would be bearing the cost of those transmission upgrades – without first evaluating all options to increase the capacity of the existing system. Pumped storage provides significant capacity value to the system and should be evaluated as both a near-term and long-term transmission solution given its capacity to absorb significant energy from renewable resources, long-discharge durations, and ability to provide the services necessary to maintain a reliable electrical system.

[13] *In the Matter of Portland General Electric Co., 2019 Integrated Resource Plan*, Comments of Swan Lake North Pumped storage LLC and the Goldendale Energy Storage Project, Docket LC 73 (April 12, 2021).

[14] PGE IRP, Figure 10.1.

Pumped storage resources provide significant, system-wide benefits to utilities such as PGE, which are seeking to integrate large amounts of renewable energy. Due to the decarbonization mandates and increased load PGE is forecasting, PGE needs to consider its transmission system's capacity and operating flexibility to reliably integrate the large scale of renewable resources. As compared to any other resource currently under consideration by PGE in the IRP, pumped storage resources are the best suited to serve these purposes, given their capacity to absorb significant energy from renewable resources, long-discharge durations, and ability to provide the services necessary to maintain a reliable electrical system.[15] Without significant storage capability on the scale of a pumped storage project to support both new and existing transmission, Swan Lake and Goldendale have concerns whether PGE meeting its clean energy mandate is even feasible.

Swan Lake and Goldendale urge PGE to evaluate pumped storage as a transmission solution in the Transmission chapter of its IRP Update. Pumped storage can serve as a maximizing capacity resource for new transmission, particularly in regards to the Bethel to Round Butte upgrade identified in the IRP. The capacity attributes of pumped storage are critical to avoid curtailment, transmission congestion, and overall costs of the transmission needs identified in the IRP. Pumped storage located at strategic points in the grid can be used to address congestion and curtailment by storing renewable energy for release at times when the transmission lines are less congested (i.e., time shifting of energy to avoid curtailments and, thereby, maximize the usage of new and existing transmission lines). Doing so improves the functionality of PGE's existing transmission, which makes it possible for PGE to integrate its new renewable resources as

[15] *What is Driving Demand for Long Duration Energy Storage?*, Navigant Research White Paper (2Q 2019), Attachment B hereto at § 1.2.2.

efficiently as possible, postponing or potentially avoiding expensive transmission upgrades throughout its system. By way of example, PGE identifies upgrading its Bethel to Round Butte 230kV line to 500kV to enable the affordable delivery of new non-emitting resources located across the Cascades to PGE's service area. The Swan Lake project is located in Klamath County, to the East of the Cascades, and connected to the Northwest AC Intertie – the major import-export line that the Bethel to Round Butte upgrade will increase access to for PGE. Thus, Swan Lake is ideally situated to maximize the capacity of the Bethel to Round Butte upgrade once it is completed and help move resources from East to West during the construction of Bethel to Round Butte. Additionally, as noted above, pumped storage can shift when generation is delivered to the system and shift when transmission is being fully utilized, allowing PGE to maximize the use of new and existing transmission to ensure ratepayers get a maximum return on investment. Furthermore, the diversity of storage and technology to meet transmission needs creates a more reliable system as PGE moves to meet its decarbonization mandates and serve load.

Swan Lake and Goldendale provide a recently-released study, the Lazard Levelized Cost of Energy Report ("Report"), as Attachment A to these comments, which further supports the comments herein emphasizing the importance of capacity resources generally – and specifically, the importance of having diversity in resources to meet decarbonization mandates. The Report shows the consequences of overreliance on certain types of resources. CAISO is an example for the Pacific Northwest of how high wind and solar penetration levels have resulted in extremely high costs to firm those resources, resulting in capacity resources becoming incredibly valuable for purposes of integrating these intermittent resources.[16] Similarly, the Report shows that high

[16] Attachment A at page 11.

penetrations have resulted in low capacity factors for renewable resources in California—in the range of 25 – 30%.[17] The Report also shows that while renewable resource costs declined rapidly between 2009 – 2014, costs have largely been steady since about 2015 – and costs have been increasing recently, likely due to supply chain shortages and massive amounts of renewable development.[18] A similar result is shown in in the graphs on page 13 of the Report, demonstrating there is actually increasing price risk and variability for solar and wind resources.[19] Swan Lake and Goldendale are concerned that over-reliance on these resources, especially without critical capacity resources such as pumped storage, could expose customers to significant price increases beyond what is modeled in the IRP.

Swan Lake and Goldendale respectfully request that PGE include pumped storage in its analysis of transmission options in Chapter 9 and the Portfolio Analysis in its IRP Update, and in particular, recognize the unique benefits that Swan Lake, by virtue of its location on the Northwest AC Intertie, brings to PGE's Bethel to Round Butte upgrade.

IV. **The IRP Relies Too Heavily on Batteries.**

Swan Lake and Goldendale urge PGE to consider whether pursuing a strategy of simultaneously bringing both batteries and pumped storage resources online is better than relying solely on batteries as system capacity resources. For example, the IRP includes 400 MW of storage additions through 2030—exclusively from 4-hour Li-ion batteries.[20] Relying solely on Li-ion batteries could expose PGE and its customers to various market factors specific to batteries,

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[17] *Id*.

[18] *Id*. at page 12.

[19] *Id*. at page 13.

[20] PGE IRP, Chapter 11 at page 289.

including commodity volatility and supply chain disruption. By adding pumped storage into the resource mix, PGE and its customers could benefit from a resource with a longer lifespan, and diversification of raw materials reliance.

Pumped storage benefits utilities by creating resource diversity in storage investments, and is well-suited to provide safe, dispatchable, reliable capacity on a scale that PGE will need to integrate the amount of renewable resources it expects to add in the next decade. Swan Lake and Goldendale urge PGE to consider whether the magnitude of reliance on battery storage additions utilities in the West warrants a consideration that its preferred portfolio will be more resilient by including more diversity in its capacity resources.

a. Pumped hydro mitigates the concerning limitations and risks of over-reliance on batteries.

Swan Lake and Goldendale are concerned about the IRP's over-reliance on batteries. PGE needs to consider a diversified approach to meeting its future dispatchable capacity needs. Such an approach requires considering technologies that can provide dispatchable, clean capacity at a scale large enough to maintain grid reliability and support customers' energy needs. Swan Lake and Goldendale are two such resources that are perfectly situated to make a significant dent in meeting PGE's future dispatchable capacity needs.

Additionally, the region is facing an unprecedented demand for battery storage, and utilities would likely benefit by starting to consider diversity in their storage resources. For example, Puget Sound Energy's preferred portfolio includes 1,000 MW of standalone storage by 2030, and 1,800

MW by 2045.[21] PacifiCorp seeks to obtain 8,095 MW of storage resources by 2042.[22] In particular, PacifiCorp's 2023 IRP preferred portfolio includes an additional 7,560 MW of proxy lithium ion battery storage by year-end 2028, 150 MW of long-duration storage by year-end 2032, and another 200 MW of long-duration storage by year-end 2036.[23] Finally, CAISO's base case portfolio includes 9 GW of new battery storage in 2031.[24] In short, the combined IRP goals call for the addition of over 20 GW of storage in the region over the next ten to twenty years. The Projects have significant concerns with the actual feasibility of constructing 20 GW of battery storage in the next ten to twenty years. Pumped storage resources help to mitigate these risks and provide reliability to the system in the face of a rapidly changing resource mix that relies on storage to meet load.

Further, pumped storage is well-suited to complement battery storage to meet PGE's significant capacity needs because other storage technologies are largely unproven for this purpose, or ill-suited to meeting these needs. Long-duration storage, such as pumped storage, allows for the efficient integration of the large amounts of renewable energy generation that is forecasted to come online, balancing costs and risks for customers and creating a reliable system. Augmenting the duration of 4-hour batteries significantly improves the grid services that PGE will be able to provide to its customers. Swan Lake and Goldendale think that PGE needs to model

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[21] Puget Sound Energy, 2023 Electric Progress Report, Table 1.1 at page. 26.

[22] PacifiCorp, 2023 Integrated Resource Plan (Mar. 31, 2023) page 2, available at: https://edocs.puc.state.or.us/efdocs/HAA/lc82haa165115.pdf.

[23] *Id.* at page 14.

[24] Decision Transferring Electric Resource Portfolios to California Independent System Operator for 2021-2022 Planning Progress, Dec. 21-02-008 (Feb. 17, 2022), p. 2, available at: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M366/K426/366426300.PDF.

long-duration storage – including pumped storage – in its portfolio analysis in the IRP Update to fully consider the effects of storage duration.

b. <u>PGE's IRP Favors Batteries Partly As a Result of Unclear, and Likely Inaccurate, Assumptions About the Useful Life of Pumped Storage Projects and PGE's Possible Failure to Factor in Tax Incentives in its Analysis of Pumped Storage.</u>

PGE's IRP analysis penalizes pumped storage with respect to these projects' expected useful life. PGE's IRP indicates it relies on NREL's Electricity Annual Technology Baseline ("ATB") and the EIA's Annual Energy Outlook 2020 ("AEO") for the resource assumptions used in PGE's IRP modeling.[25] However, after reviewing the ATB, AEO and NPCC Reference Plants, it isn't clear what figures PGE is using for the useful life of a pumped storage asset in the IRP. Section 8.1.8.2 of PGE's IRP discusses pumped storage resource characteristics but does not specifically state what useful life is being assumed for purposes of cost comparisons to other resources. The data sets that PGE relies upon differ in their assumptions about useful life. For example, the ATB has selectable capital recovery periods of 20, 30 or 100 years, and notably identifies the technology life of pumped storage as 100 years. Comparatively, the AEO uses a 50-year useful life for *any* type of hydro asset with storage, including pumped storage – and the NPCC Reference Plants report also uses a 50 year "economic life". Given the inconsistency in the data sets with respect to the appropriate useful life of a pumped storage asset, Swan Lake and Goldendale request that PGE clarify what useful life it is using and run a sensitivity to its IRP analysis that uses a 100-year useful life, as shown in ATB. 100 years is a reasonable useful life considering the numerous examples of currently operating hydro assets in the Pacific Northwest

[25] PGE IRP, Section 8.1.2.1, footnotes 207 and 208.

that were put into operation nearly 100 years ago and which are expected to continue operating at or beyond the 100-year mark.[26]

By using a more accurate useful life for pumped storage projects, we expect PGE and its customers to see significant cost savings, both in the levelized cost in comparison to other resources, but also in the form of highly-valuable, dispatchable resources that, once depreciated, will be amongst the most economical in PGE's resource fleet. Today, many Pacific Northwest utilities rely on the ageing hydro system for their low-cost power, and investing in pumped storage assets like Swan Lake and Goldendale will ensure PGE has similar resources in its fleet for the next 100 years to continue providing low-cost power for PGE customers.

Additionally, it is unclear whether PGE factored in the estimated cost reductions of Investment Tax Credits and Production Tax Credits ("ITCs" and "PTCs") for pumped hydro in light of the passage of the Federal Inflation Reduction Act ("IRA"). In Figure 14 of the IRP, PGE demonstrates the estimated cost reduction from the IRA for "select" generation sources – 4-hour Storage, Solar in Christmas Valley, Offshore Wind, and Onshore Wind.[27] Given that the ITCs and PTCs also apply to pumped storage, it is unclear why PGE did not include it in this group of resources. Further, PGE states that the modeling in the IRP "assumes incremental resources are eligible for the 100 percent level of applicable tax credits."[28] Based on this statement, Swan Lake and Goldendale are not sure whether this applies to how PGE modeled pumped storage in the IRP, and would like clarification to ensure the tax credits for pumped storage are accurately modeled.

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[26] *E.g.*, Rock Island Dam (opened 1933); Bonneville Dam (opened 1938); Cushman Dam (opened 1921); Grand Coulee Dam (opened 1942).

[27] PGE IRP, Figure 14 at page 42.

[28] *Id*., Chapter 2 at page 43.

Once these assumptions are corrected and all types of storage resources are fairly evaluated on an apple-to-apples basis, Swan Lake and Goldendale are confident that pumped storage would be amongst the lowest cost storage resources available to PGE and its ratepayers.

c. PGE's IRP Mischaracterizes, or Uses Incorrect Assumptions, In Its Analysis of Batteries.

Swan Lake and Goldendale request that PGE re-run its portfolio analysis in its IRP Update addressing and/or correcting the following issues:

1. The IRP mistakenly shows that a 10-hour pumped storage facility has a lower flexibility value than an 8-hour battery.[29] The Projects urge PGE to reconsider this determination.

2. The IRP shows that pumped storage has a lower O/N capital cost on a per-kWh basis than 4-hour batteries. The Projects urge PGE to consider whether this benefit has been taken into account in determining the preferred portfolio.

3. Appendix M, Section M.3.1 shows that pumped storage is cost-competitive with a similarly-sized battery when looking at overnight capital costs, despite pumped storage's proven use case, long and reliable operational history, and ability to provide significant amounts of capacity to PGE.[30] To the extent PGE did not factor in ITCs and PTCs into these figures, Swan Lake and Goldendale believe that the cost of pumped storage could be significantly more competitive with batteries if PGE were to incorporate those into this section.

[29] *Id.* at Table 47.

[30] Compare PGE IRP, Table 154 (location adjusted overnight capital cost for an 8-hour battery system) with Table 159 (overnight capital cost of a pumped storage system).

Swan Lake and Goldendale respectfully request that PGE model pumped storage in its portfolio analysis to address the concerns of overreliance on batteries explained above and address and/or correct the issues outlined above in its IRP Update.

V. Conclusion

The Projects appreciate the opportunity to provide these comments on the IRP. For the reasons set forth in these comments, Swan Lake and Goldendale request that PGE re-run its Preferred Portfolio analysis with the following changes: (1) remove pumped storage as an "emerging technology" and correct/address the mistaken assumptions of pumped hydro; (2) include the significant benefits pumped storage can provide to the transmission needs identified in the IRP; and (3) consider pumped storage for PGE's capacity and storage needs rather than relying exclusively on batteries and correct/address the issues identified herein. These changes are warranted for the reasons described above, but are also necessary to ensure that the Preferred Portfolio meets the Commission's IRP Guidelines of providing the "best combination of expected costs and associated risks and uncertainties for the utility and its customers."[31]

Please contact the undersigned with any questions or concerns.

Dated this 4th day of May, 2023.

[31] Commission IRP Guidelines, Guideline 1(c).

Respectfully submitted,

<u>/s/ Michael Rooney</u>

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Attachment A

APRIL 2023

LCOE+

LAZARD

With support from Roland Berger

LAZARD

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Attachment A

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

LAZARD

Introduction

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

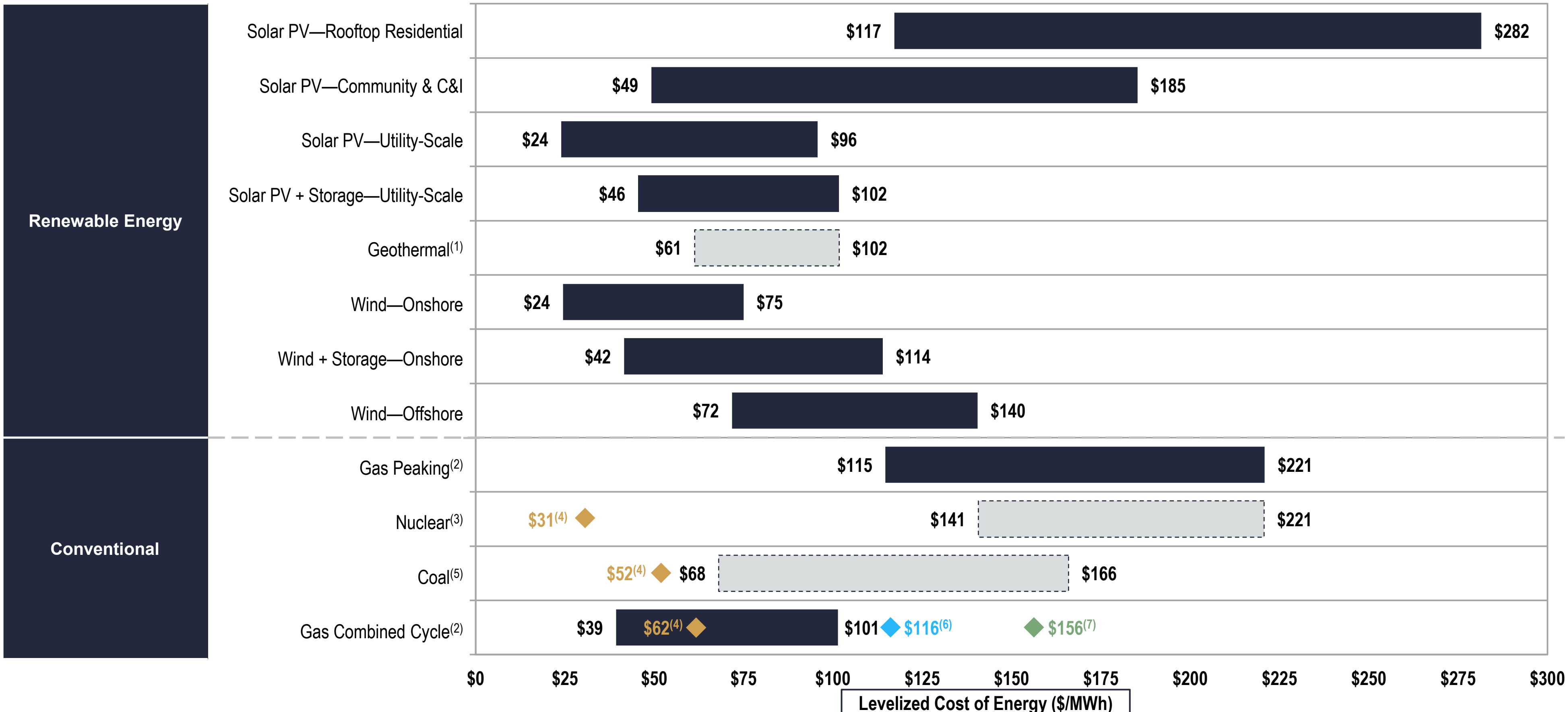
- **Comparative LCOE analysis for various generation technologies on a $/MWh basis, including sensitivities for U.S. federal tax subsidies, fuel prices, carbon pricing and cost of capital**
- **Illustration of how the LCOE of onshore wind, utility-scale solar and hybrid projects compare to the marginal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

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

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

Levelized Cost of Energy Comparison—Unsubsidized Analysis

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



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

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

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

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

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

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

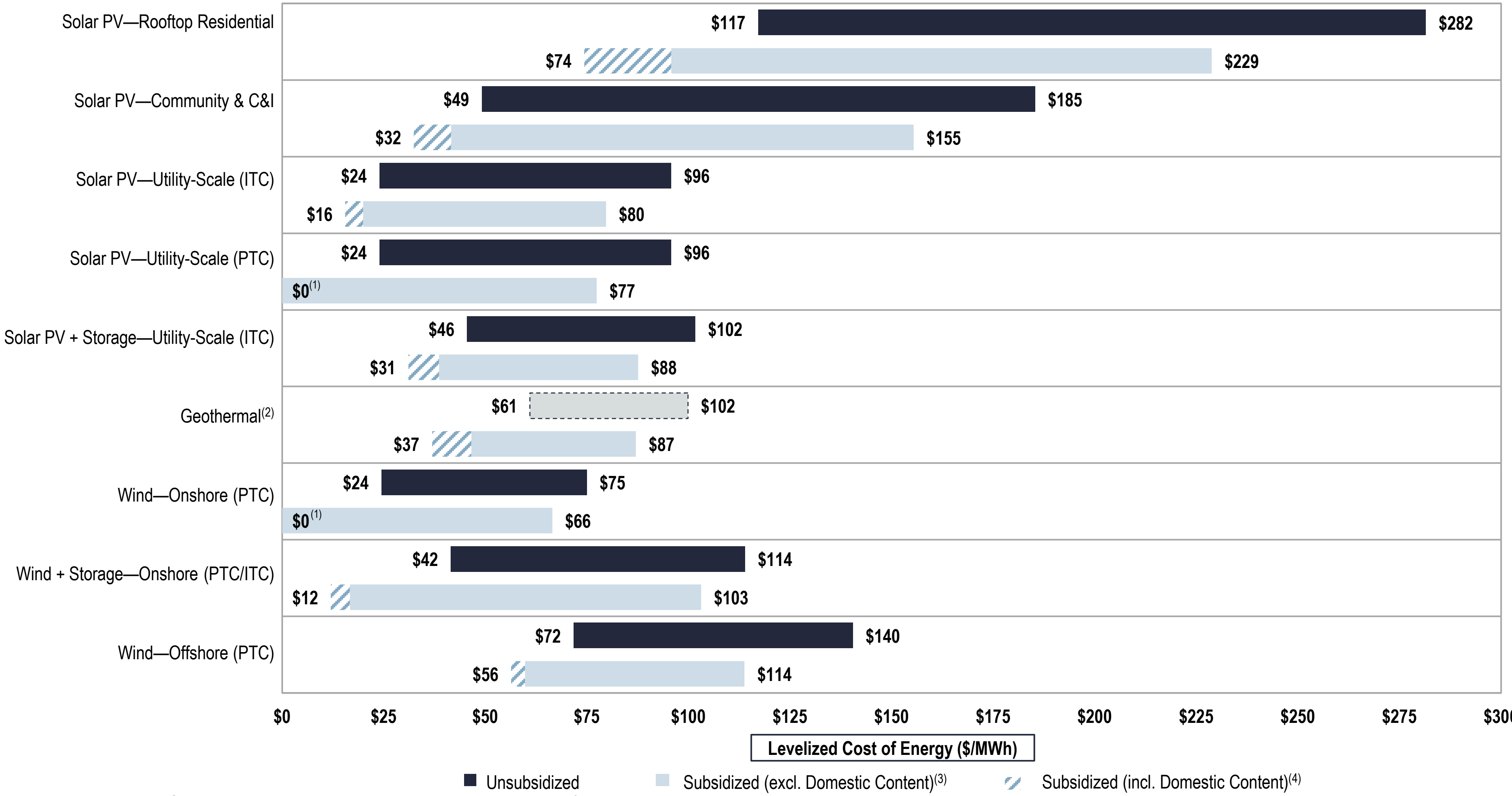
(5) Given the limited public and/or observable data set available for new-build coal projects, the LCOE presented herein represents Lazard's LCOE v15.0 results adjusted for inflation. High end incorporates 90% carbon capture and storage ("CCS"). Does not include cost of transportation and storage.

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

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

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

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



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

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

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

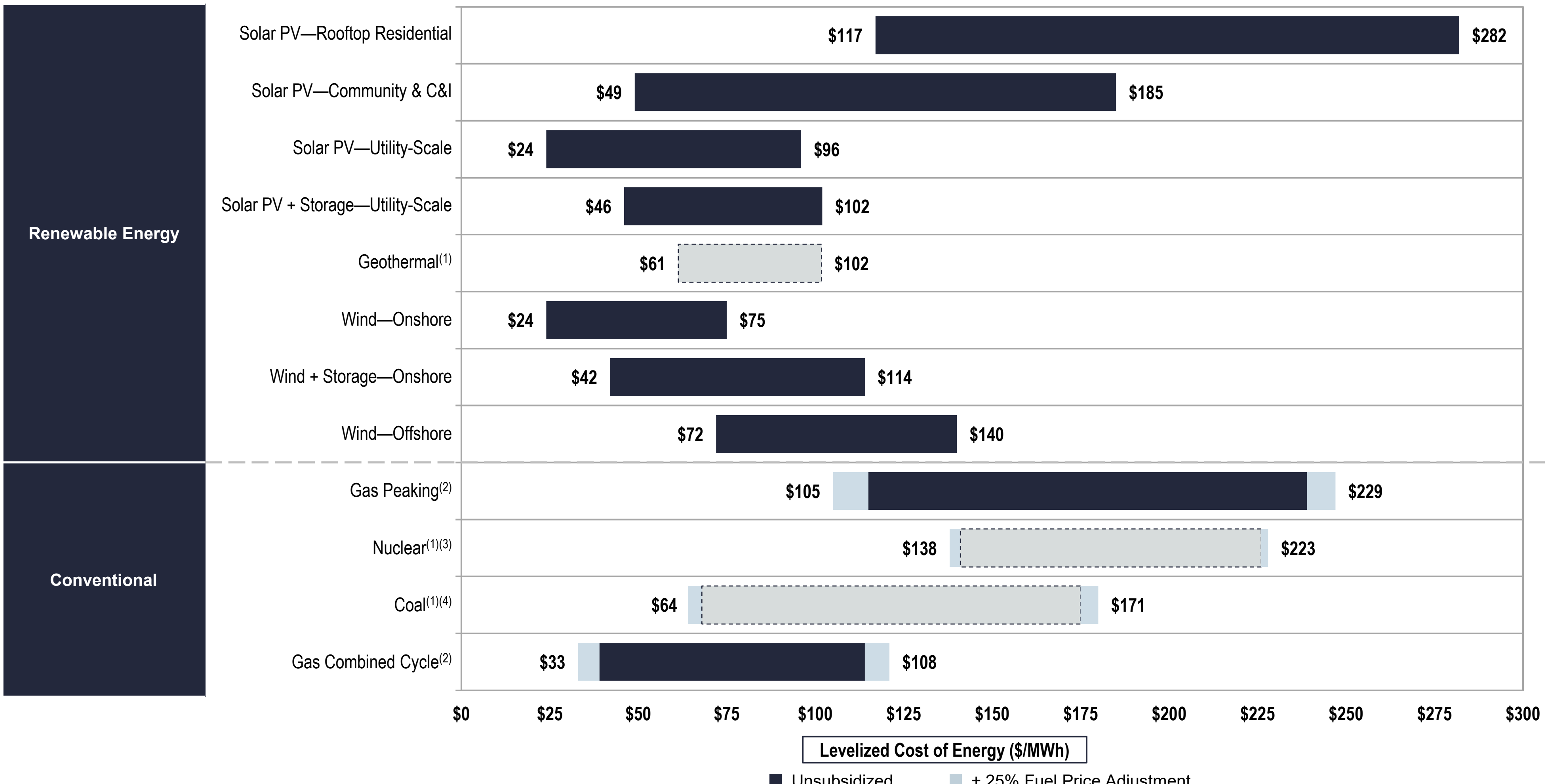
(2) Given the limited public and/or observable data set available for new-build geothermal projects, the LCOE presented herein represents Lazard's LCOE v15.0 results adjustment for inflation.

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

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

Levelized Cost of Energy Comparison—Sensitivity to Fuel Prices

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



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

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

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

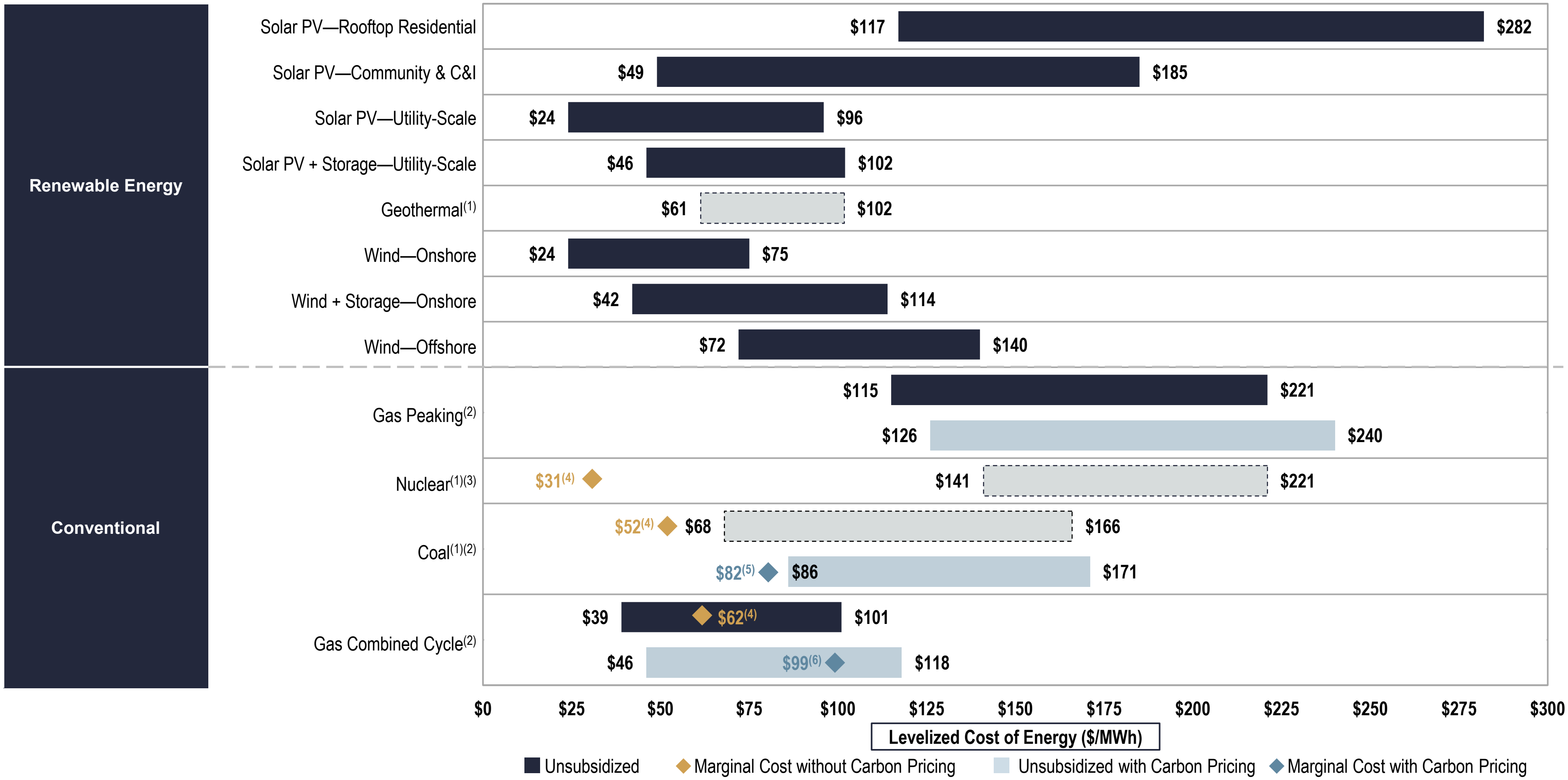
(2) Assumes a fuel cost range for gas-fired generation resources of $2.59/MMBTU – $4.31/MMBTU (representing a sensitivity range of ± 25% of the $3.45/MMBTU used in the Unsubsidized Analysis).

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

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

Levelized Cost of Energy Comparison—Sensitivity to Carbon Pricing

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



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

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

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

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

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

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

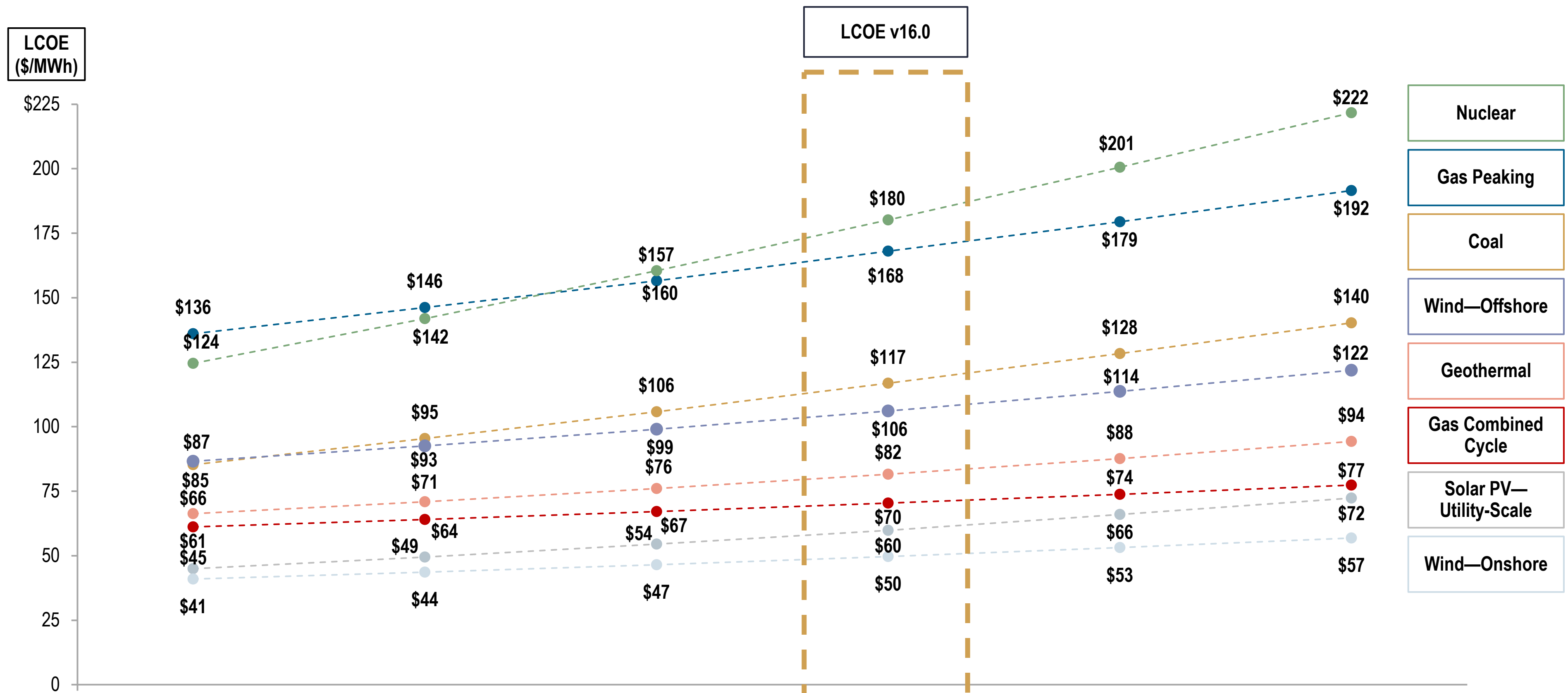
(5) Represents the midpoint of the unsubsidized marginal cost of operating fully depreciated coal facilities with illustrative carbon pricing. Operating coal facilities are not assumed to employ CCS technology.

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

Levelized Cost of Energy Comparison—Sensitivity to Cost of Capital

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

Midpoint of Unsubsidized LCOE[2]



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

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

Note: Analysis assumes 60% debt and 40% equity. Unless otherwise noted, the assumptions used in this sensitivity correspond to those used on the page titled "Levelized Cost of Energy Comparison—Unsubsidized Analysis".

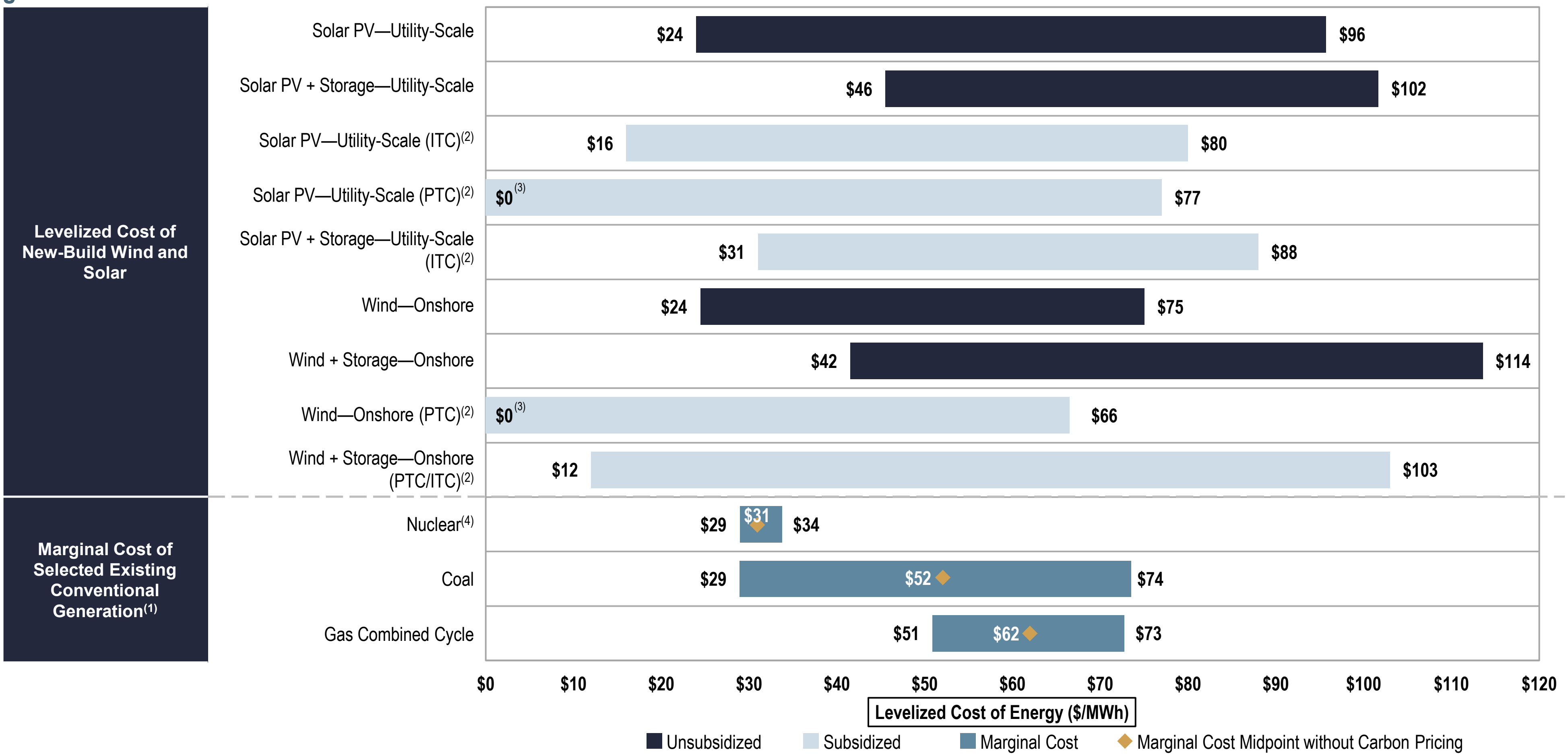
(1) Cost of capital as used herein indicates the cost of capital applicable to the asset/plant and not the cost of capital of a particular investor/owner.

(2) Reflects the average of the high and low LCOE for each respective cost of capital assumption.

Attachment A

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

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



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

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

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

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

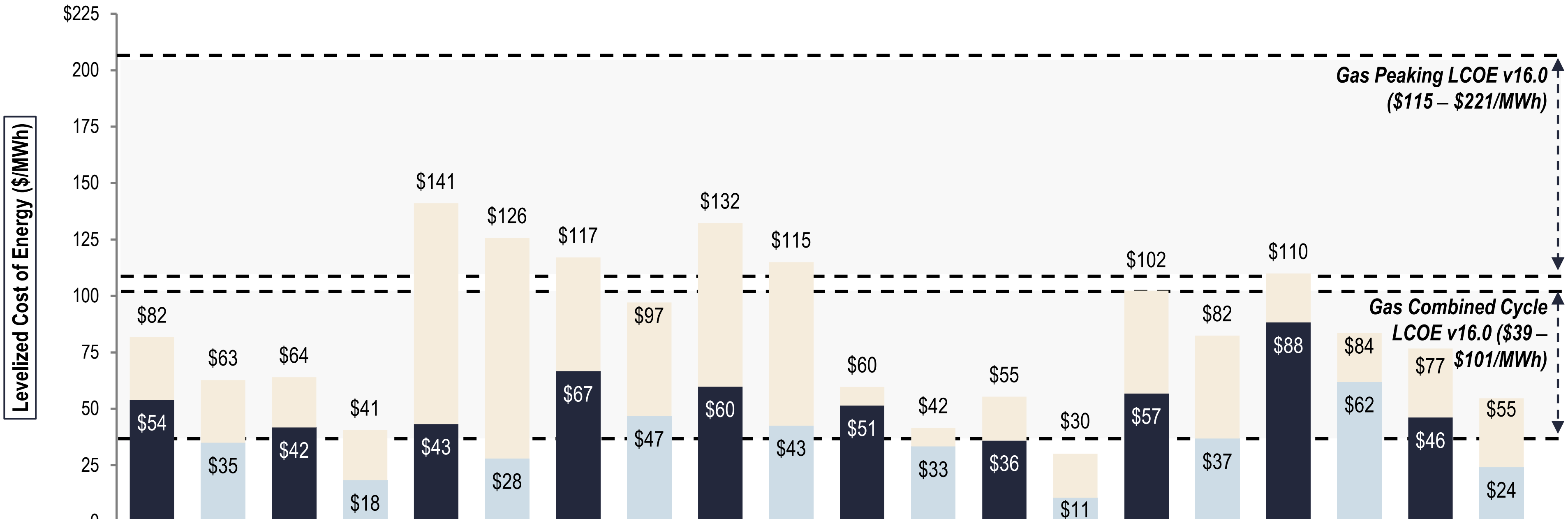
(3) Results at this level are driven by Lazard's approach to calculating the LCOE and selected inputs (see Appendix for further details). Lazard's Unsubsidized LCOE analysis assumes, for year-over-year reference purposes, 60% debt at an 8% interest rate and 40% equity at a 12% cost (together implying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

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

Levelized Cost of Energy Comparison—Cost of Firming Intermittency

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

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



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

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

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

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

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

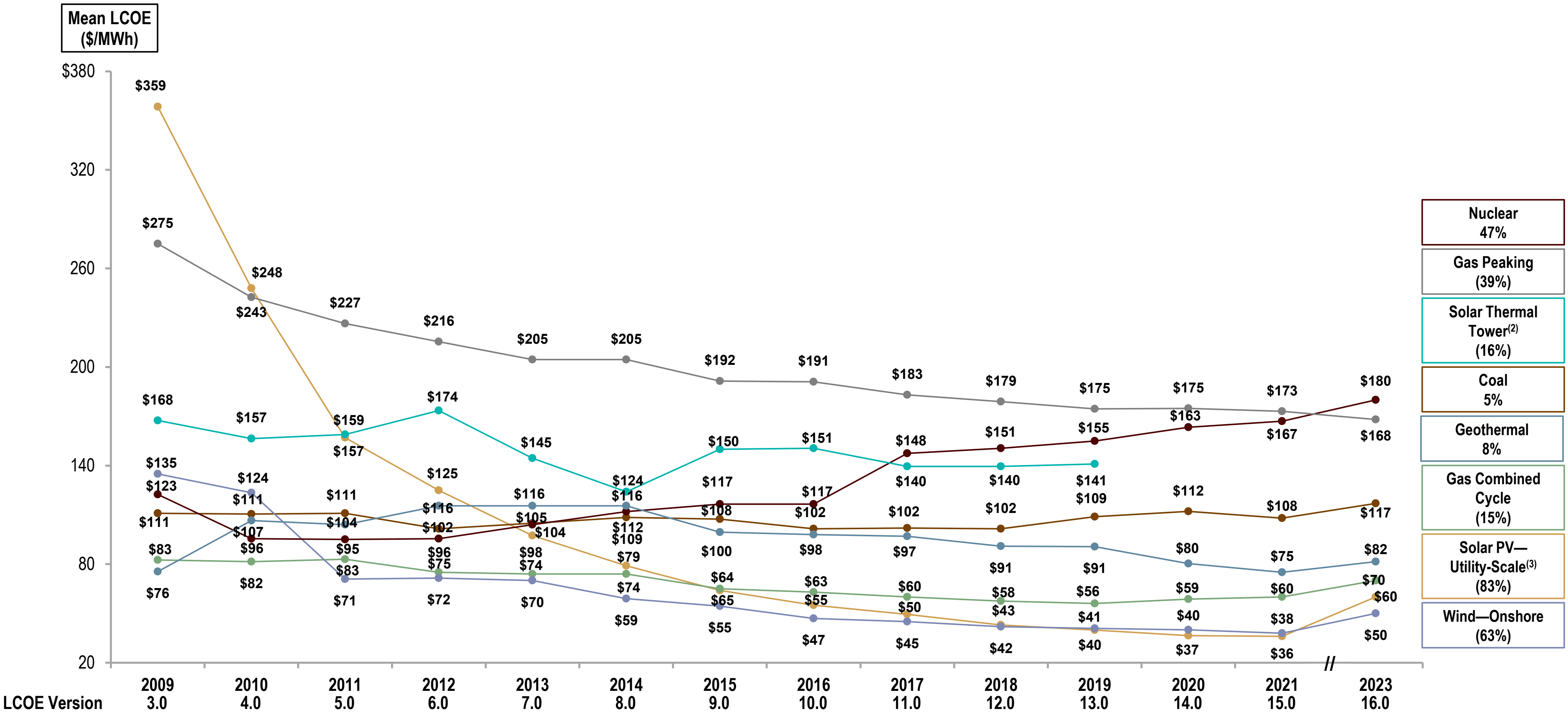
(3) LCOE values represent the midpoint of Lazard's LCOE v16.0 cost inputs for each technology adjusted for a regional capacity factor to demonstrate the regional differences in both project and firming costs.

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

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

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

Selected Historical Mean Unsubsidized LCOE Values[1]



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

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

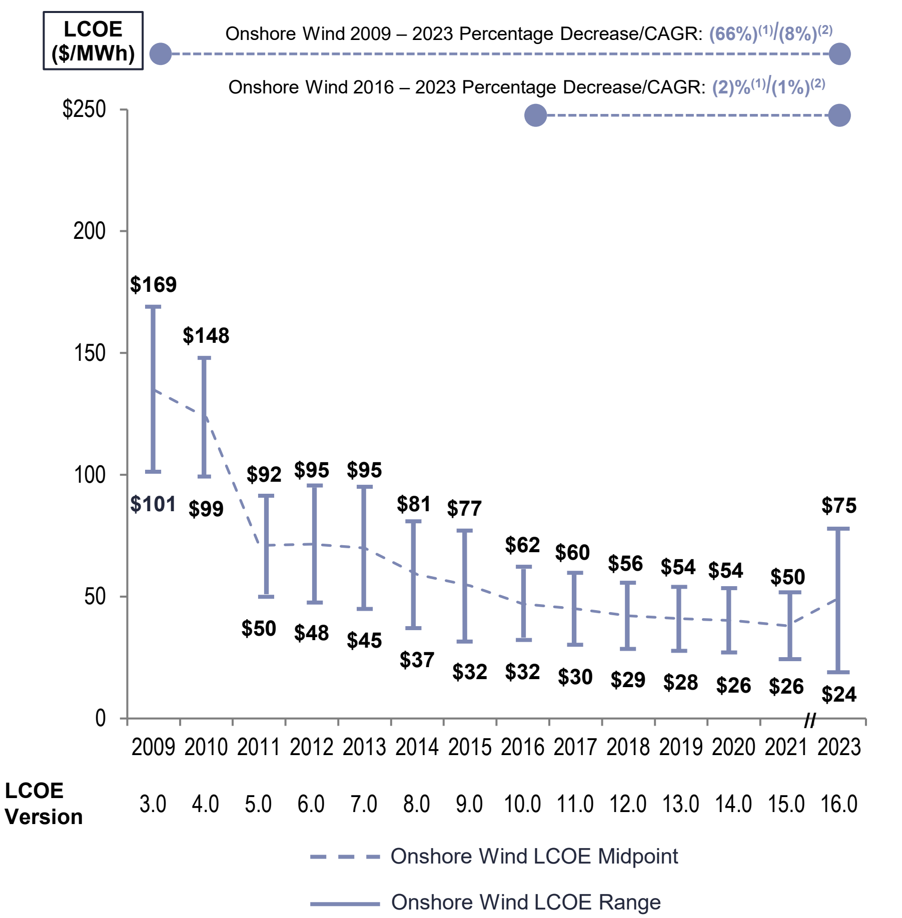
(2) The LCOE no longer analyzes solar thermal costs; percent decrease is as of Lazard's LCOE v13.0.

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

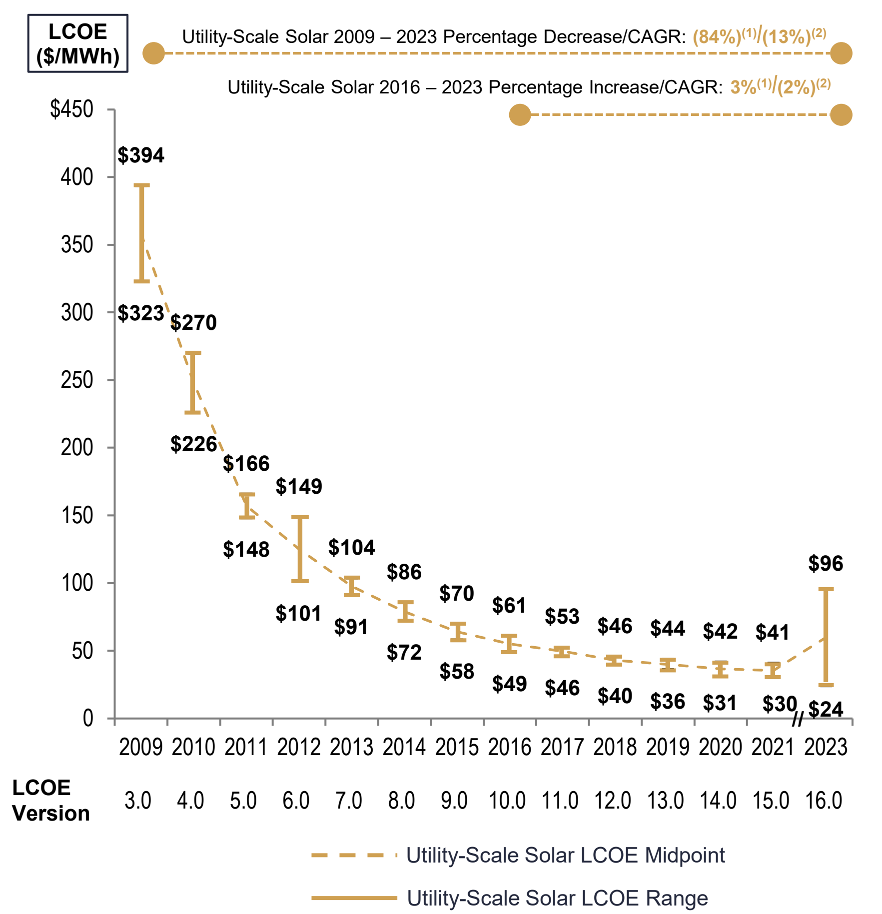
Levelized Cost of Energy Comparison—Historical Renewable Energy LCOE

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

Unsubsidized Onshore Wind LCOE



Unsubsidized Solar PV LCOE



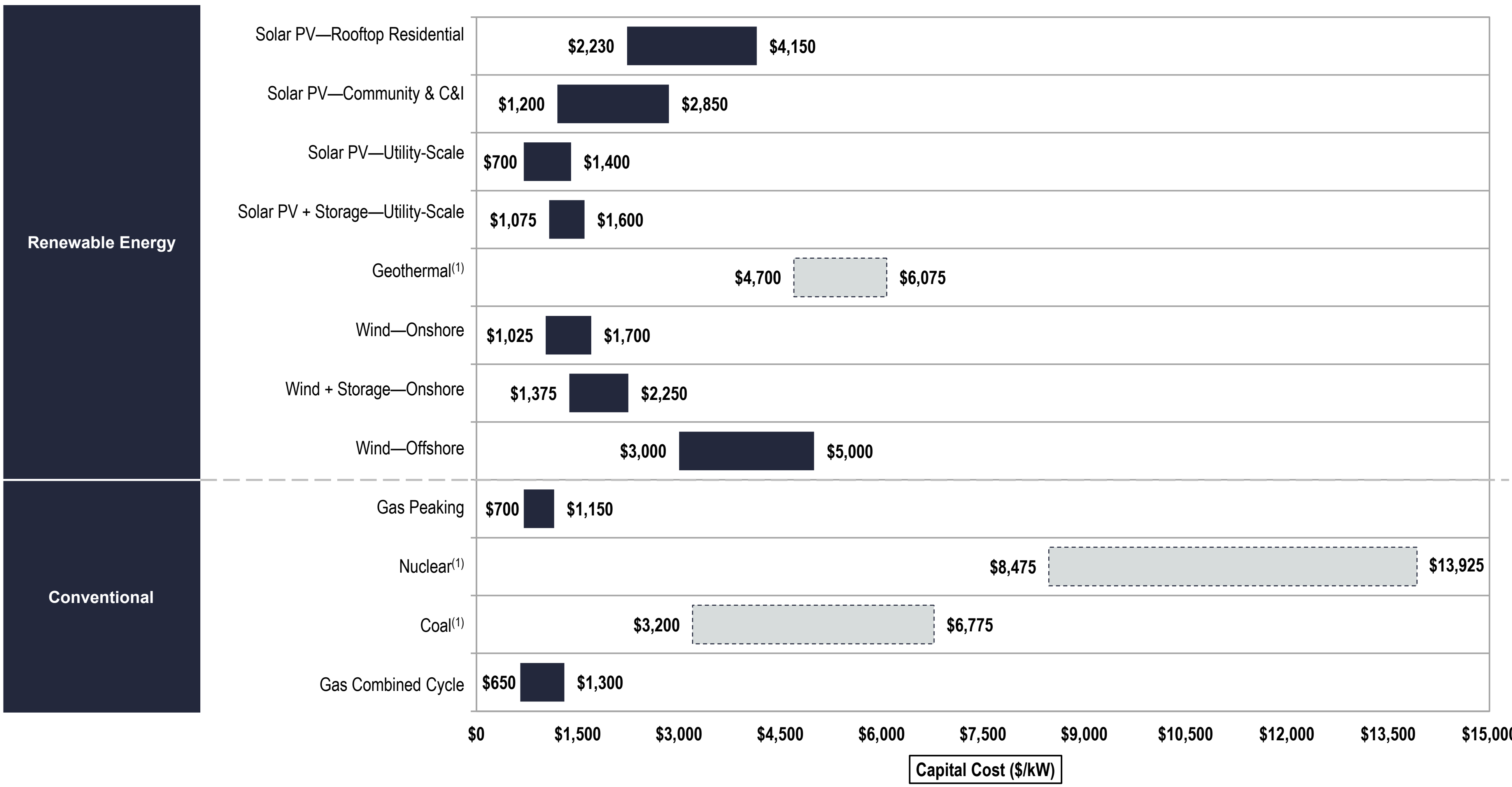
Source: Lazard and Roland Berger estimates and publicly available information.

(1) Represents the average percentage decrease/increase of the high end and low end of the LCOE range.

(2) Represents the average compounded annual rate of decline of the high end and low end of the LCOE range.

Levelized Cost of Energy Comparison—Capital Cost Comparison

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



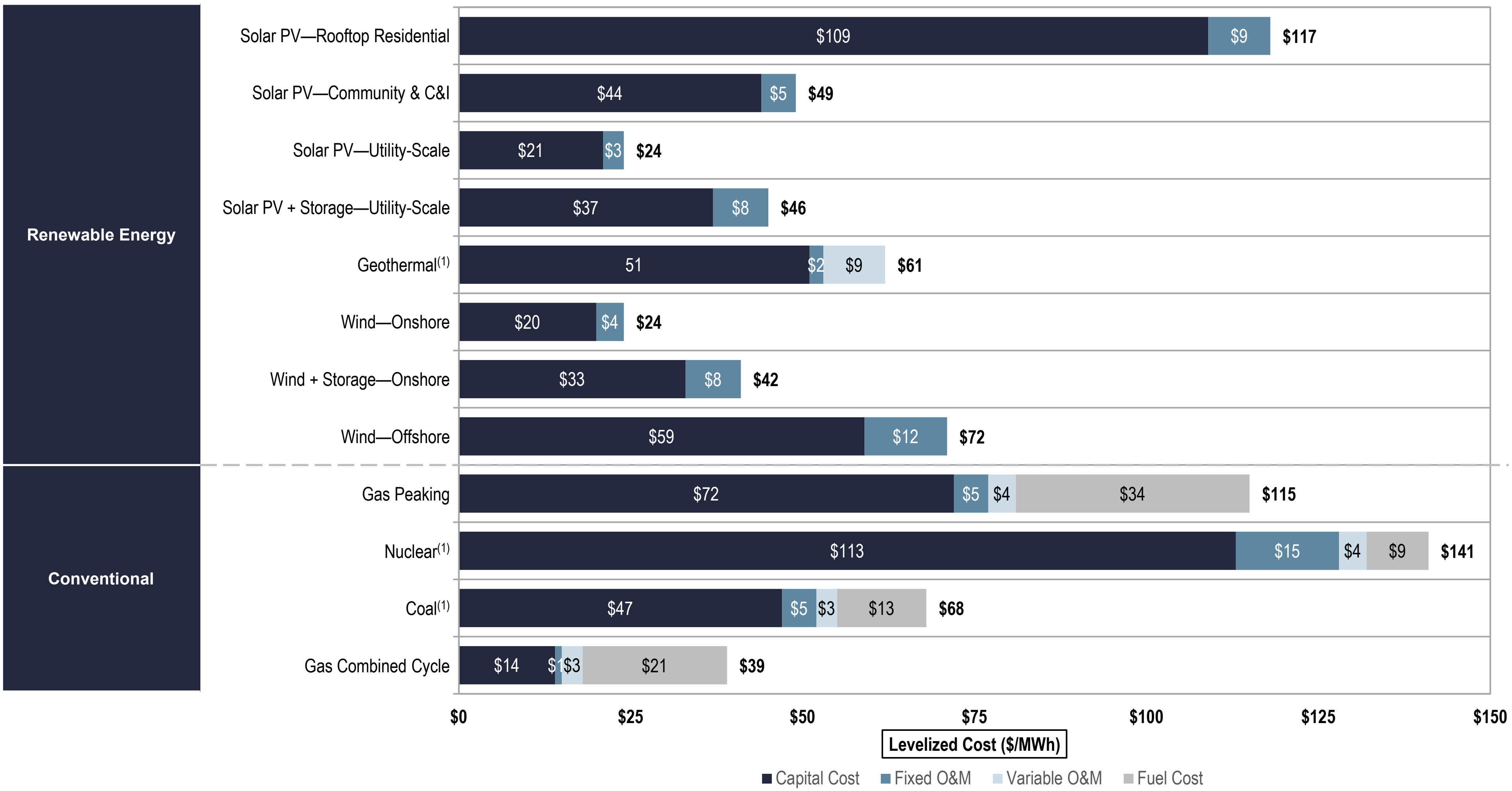
Source: *Lazard and Roland Berger estimates and publicly available information.*

Notes: Figures may not sum due to rounding.

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

Levelized Cost of Energy Components—Low End

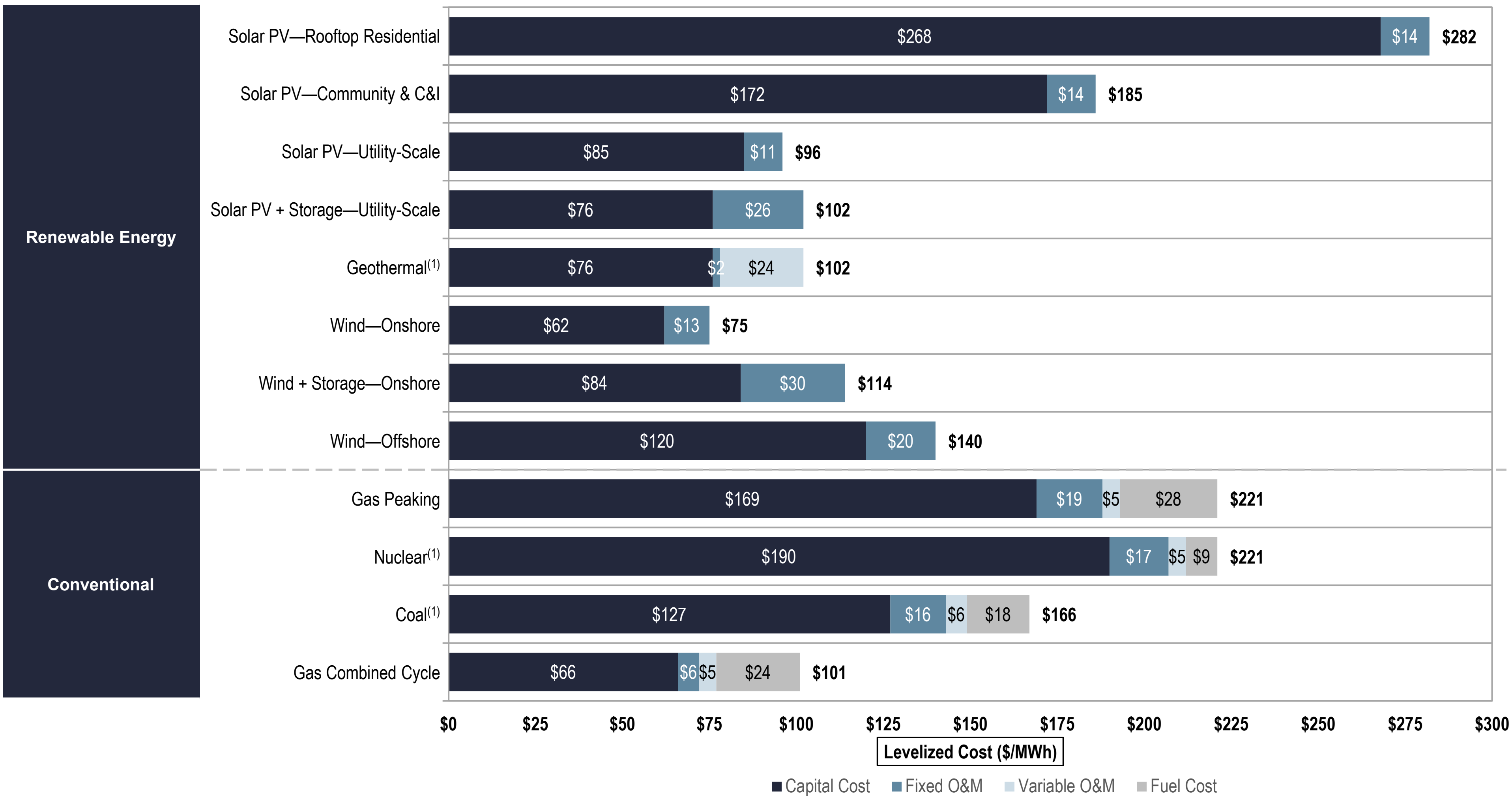
Certain renewable energy generation technologies are already cost-competitive with conventional generation technologies; key factors regarding the continued cost decline of renewable energy generation technologies are the ability of technological development and industry scale to continue lowering operating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



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

Levelized Cost of Energy Components—High End

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



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

Notes: Figures may not sum due to rounding.

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

Energy Resources—Matrix of Applications

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

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

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

APRIL 2023

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

LAZARD

Introduction

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

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

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

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

Energy Storage Use Cases—Overview

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

		Use Case Description	Technologies Assessed
In-Front-of-the-Meter	① Utility-Scale (Standalone)	• Large-scale energy storage system designed for rapid start and precise following of dispatch signal. Variations in system discharge duration are designed to meet varying system needs (i.e., short-duration frequency regulation, longer-duration energy arbitrage[1] or capacity, etc.) – To better reflect current market trends, this report analyzes one-, two- and four-hour durations[2]	• Lithium Iron Phosphate (LFP) • Lithium Nickel Manganese Cobalt Oxide (NMC)
In-Front-of-the-Meter	② Utility-Scale (PV + Storage)	• Energy storage system designed to be paired with large solar PV facilities to better align timing of PV generation with system demand, reduce curtailment and provide grid support	• Lithium Iron Phosphate (LFP) • Lithium Nickel Manganese Cobalt Oxide (NMC)
In-Front-of-the-Meter	③ Utility-Scale (Wind + Storage)	• Energy storage system designed to be paired with large wind generation facilities to better align timing of wind generation with system demand, reduce curtailment and provide grid support	• Lithium Iron Phosphate (LFP) • Lithium Nickel Manganese Cobalt Oxide (NMC)
Behind-the-Meter	④ Commercial & Industrial (Standalone)	• Energy storage system designed for behind-the-meter peak shaving and demand charge reduction for C&I users – Units often configured to support multiple commercial energy management strategies and provide optionality for the system to provide grid services to a utility or the wholesale market, as appropriate, in a given region	• Lithium Iron Phosphate (LFP) • Lithium Nickel Manganese Cobalt Oxide (NMC)
Behind-the-Meter	⑤ Commercial & Industrial (PV + Storage)	• Energy storage system designed for behind-the-meter peak shaving and demand charge reduction services for C&I users – Systems designed to maximize the value of the solar PV system by optimizing available revenue streams and subsidies	• Lithium Iron Phosphate (LFP) • Lithium Nickel Manganese Cobalt Oxide (NMC)
Behind-the-Meter	⑥ Residential (Standalone)	• Energy storage system designed for behind-the-meter residential home use—provides backup power and power quality improvements – Depending on geography, can arbitrage residential time-of-use (TOU) rates and/or participate in utility demand response programs	• Lithium Iron Phosphate (LFP) • Lithium Nickel Manganese Cobalt Oxide (NMC)
Behind-the-Meter	⑦ Residential (PV + Storage)	• Energy storage system designed for behind-the-meter residential home use—provides backup power, power quality improvements and extends usefulness of self-generation (e.g., PV + storage) – Regulates the power supply and smooths the quantity of electricity sold back to the grid from distributed PV applications	• Lithium Iron Phosphate (LFP) • Lithium Nickel Manganese Cobalt Oxide (NMC)

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

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

(2) The Value Snapshot analysis only evaluates the 4 hour utility-scale use case.

Energy Storage Use Cases—Illustrative Operational Parameters

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

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

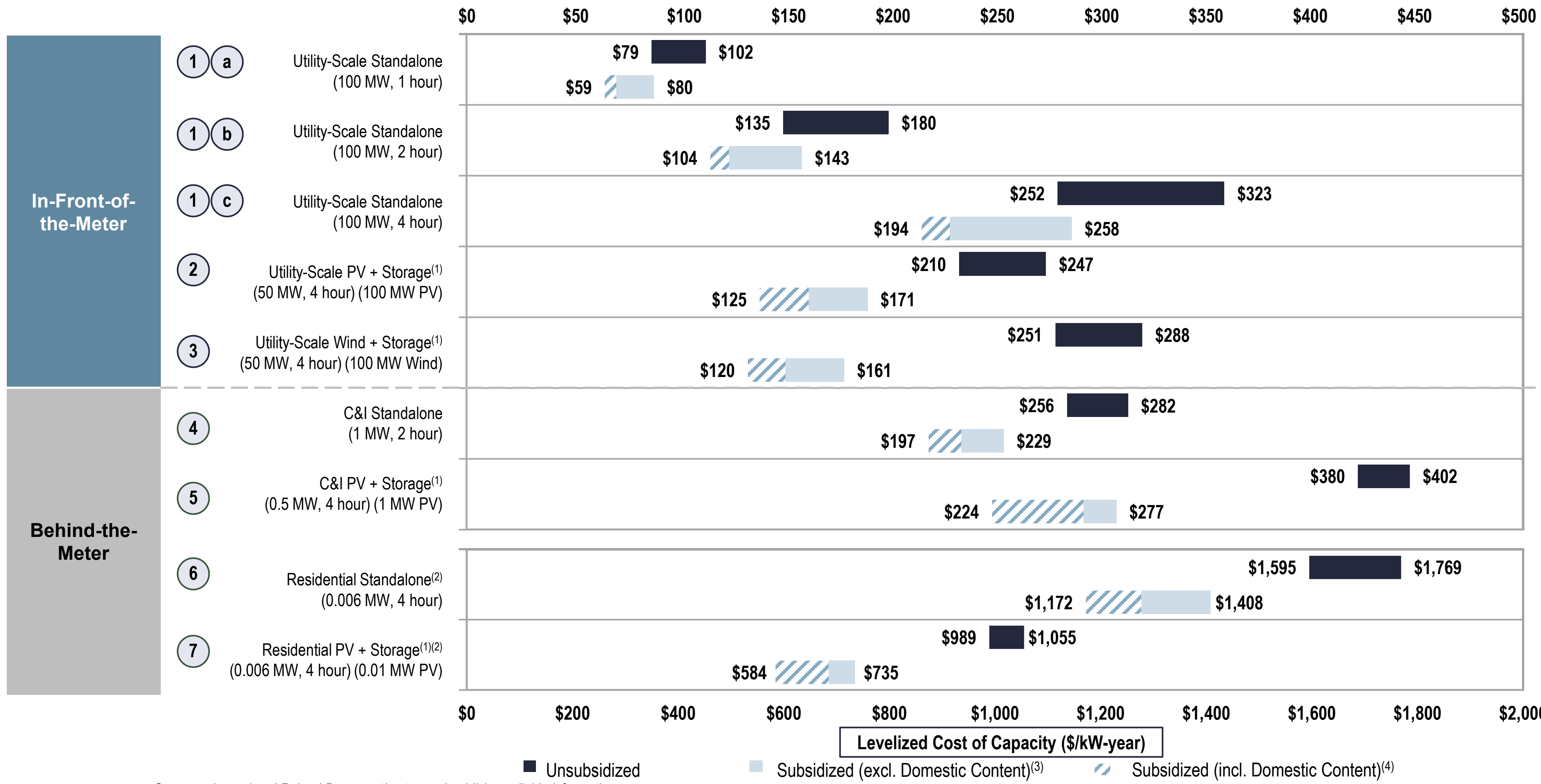
[dashed box] = "Usable Energy"(2)

			A: Project Life (Years)	B: Storage (MW)(3)	Solar/ Wind (MW)	Battery Degradation (per annum)	C: Storage Duration (Hours)	D = B x C: Nameplate Capacity (MWh)(4)	E: 90% DOD Cycles/ Day(5)	F: Days/ Year(6)	G = D x E x F: Annual MWh(7)	H = A x G: Project MWh
In-Front-of-the-Meter	1 Utility-Scale (Standalone)	a	20	100	–	2.6%	1	100	1	350	31,500	630,000
		b	20	100	–	2.6%	2	200	1	350	63,000	1,260,000
		c	20	100	–	2.6%	4	400	1	350	126,000	2,520,000
	2 Utility-Scale (PV + Storage)(8)		20	50	100	2.6%	4	200	1	350	191,000	3,820,000
	3 Utility-Scale (Wind + Storage)(8)		20	50	100	2.6%	4	200	1	350	366,000	7,320,000
Behind-the-Meter	4 Commercial & Industrial (Standalone)		20	1	–	2.6%	2	2	1	350	630	12,600
	5 Commercial & Industrial (PV + Storage)(8)		20	0.50	1	2.6%	4	2	1	350	1,690	33,800
	6 Residential (Standalone)		20	0.006	–	1.9%	4	0.025	1	350	8	158
	7 Residential (PV + Storage)(8)		20	0.006	0.010	1.9%	4	0.025	1	350	15	300

Source: *Lazard and Roland Berger estimates and publicly available information.*
Note: Operational parameters presented herein are applied to Value Snapshot and LCOS calculations. Annual and Project MWh in the Value Snapshot analysis may vary from the representative project.
(1) The use cases herein represent illustrative current and contemplated energy storage applications.
(2) Usable energy indicates energy stored and available to be dispatched from the battery.
(3) Indicates power rating of system (i.e., system size).
(4) Indicates total battery energy content on a single, 100% charge, or "usable energy". Usable energy divided by power rating (in MW) reflects hourly duration of system. This analysis reflects common practice in the market whereby batteries are upsized in year one to 110% of nameplate capacity (e.g., a 100 MWh battery actually begins project life with 110 MWh).
(5) "DOD" denotes depth of battery discharge (i.e., the percent of the battery's energy content that is discharged). A 90% DOD indicates that a fully charged battery discharges 90% of its energy. To preserve battery longevity, this analysis assumes that the battery never charges over 95%, or discharges below 5%, of its usable energy.
(6) Indicates number of days of system operation per calendar year.
(7) Augmented to nameplate MWh capacity as needed to ensure usable energy is maintained at the nameplate capacity, based on Year 1 storage module cost.
(8) For PV + Storage and Wind + Storage cases, annual MWh represents the net output of combined system (generator output, less storage "round trip efficiency" losses) assuming 100% storage charging from the generator.

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

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



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

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

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

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

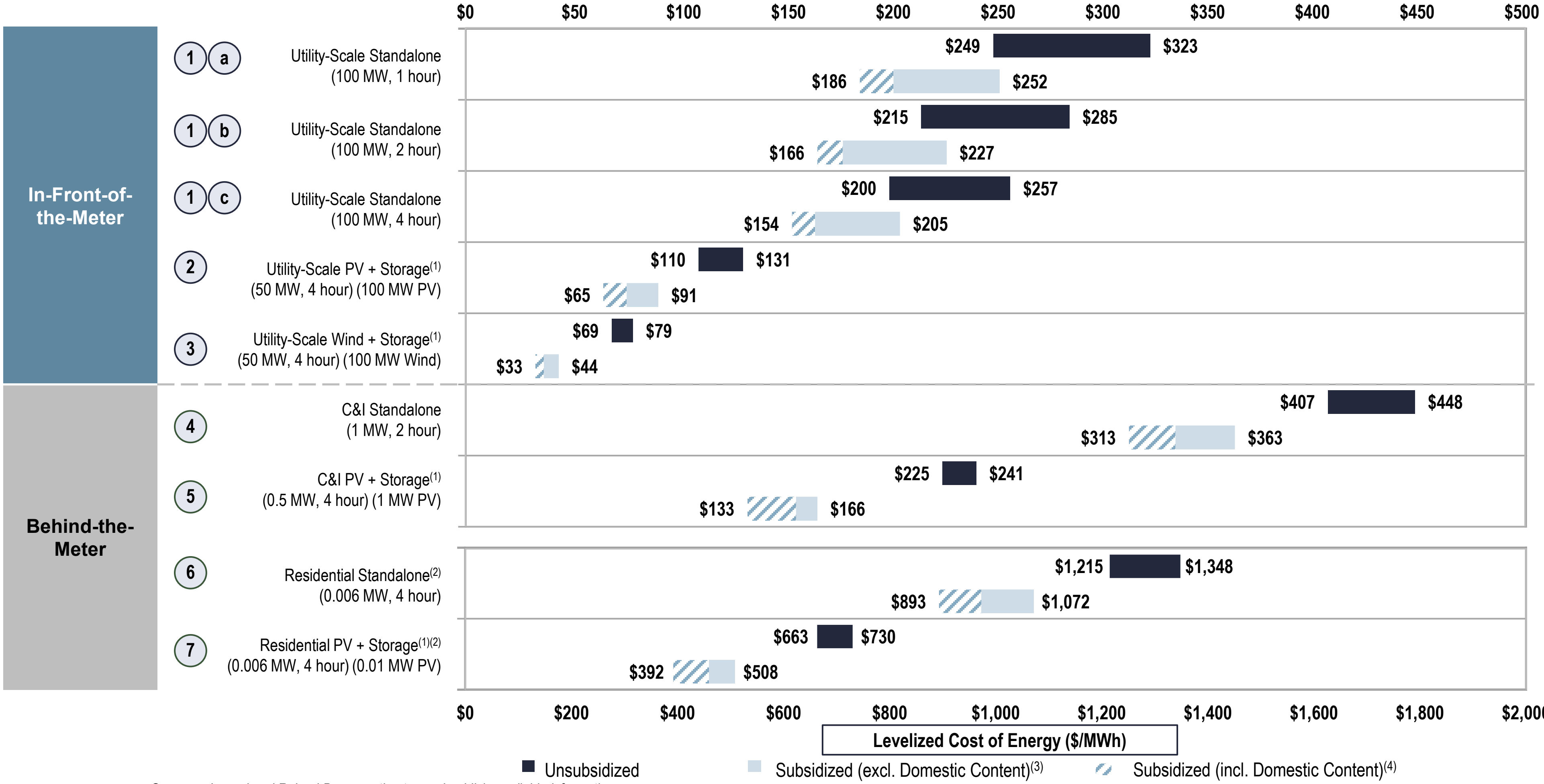
(3) This sensitivity analysis assumes that projects qualify for the full ITC/PTC and have a capital structure that includes sponsor equity, debt and tax equity. In this analysis only the wind portion of the Wind + Storage system utilizes the PTC.

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

Attachment A

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

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



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

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

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

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

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

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

Value Snapshots—Revenue Potential for Relevant Use Cases

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

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

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

Source: *Lazard and Roland Berger estimates, Enovation Analytics and publicly available information.*
(1) Represents the universe of potential revenue streams available to the various use cases. Does not represent the use cases analyzed in the Value Snapshots.

Value Snapshot Case Studies—Overview

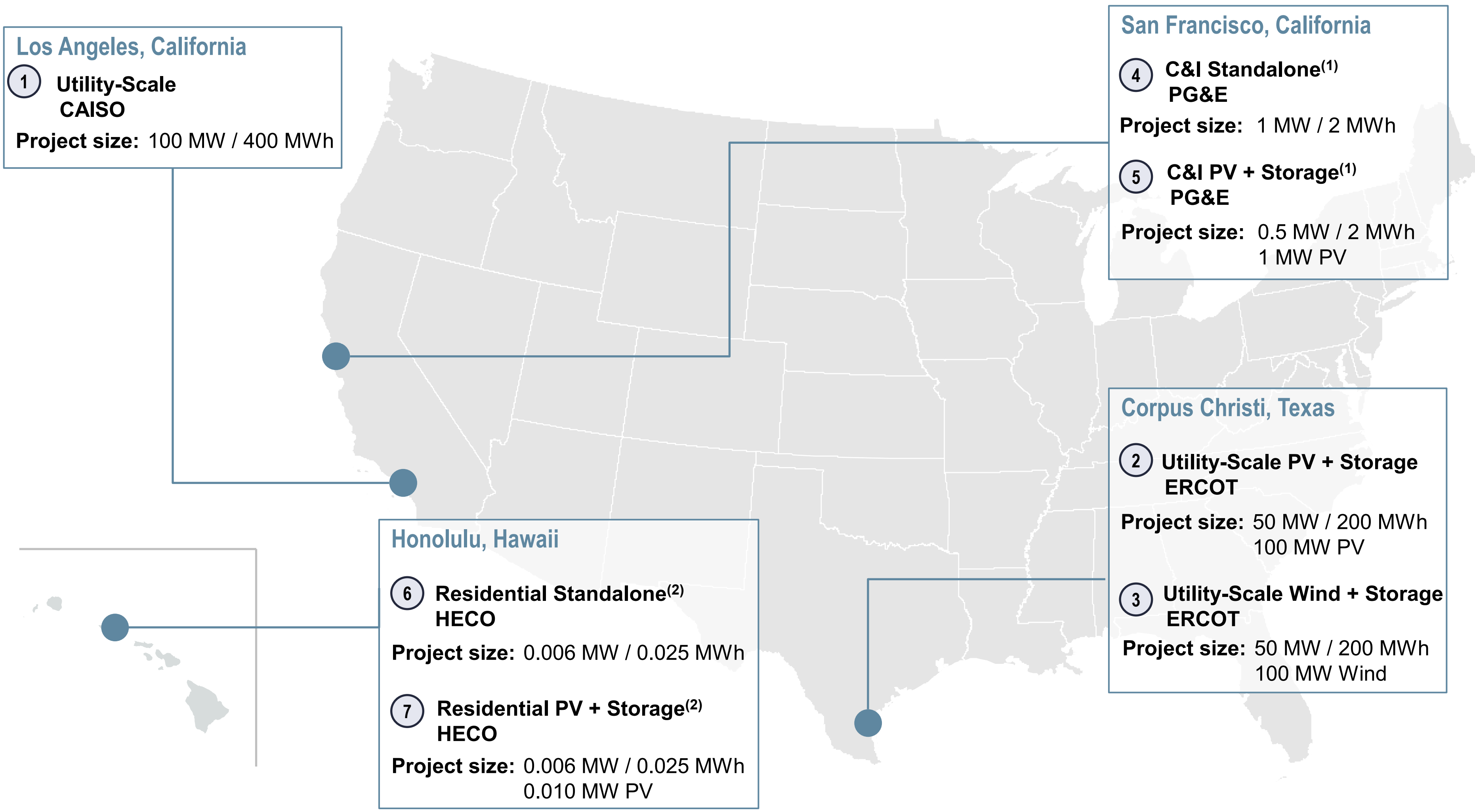
Lazard's Value Snapshots analyze the financial viability of illustrative energy storage systems designed for selected use cases

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

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

Value Snapshot Case Studies—Overview (cont'd)

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



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

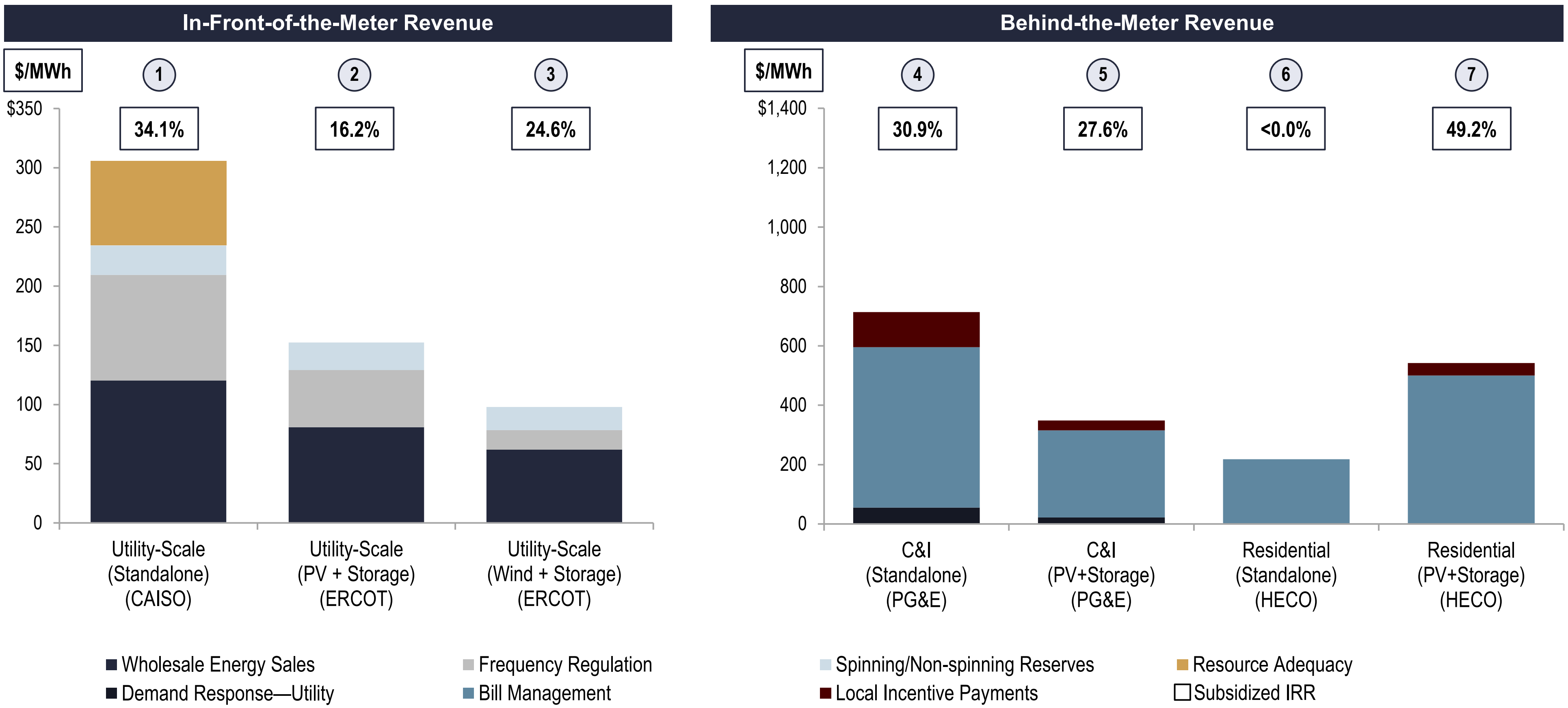
Note: Project parameters (i.e., battery size, duration, etc.) presented above correspond to the inputs used in the LCOS analysis.

(1) Assumes the project provides services under contract with PG&E.

(2) Assumes the project provides services under contract with HECO.

Value Snapshot Case Studies—Summary Results

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



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

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

APRIL 2023

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

LAZARD

Introduction

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

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

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

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

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

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

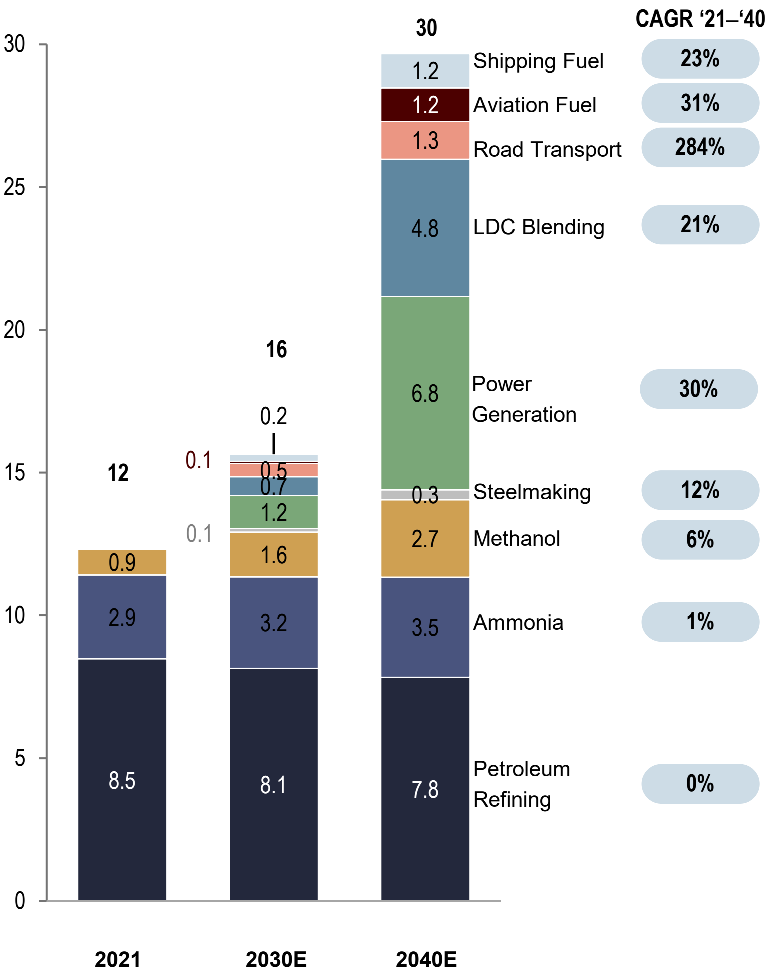
Technology Overview & Commercial Readiness	Hydrogen and Hydrogen Production • Hydrogen is currently produced primarily from fossil fuels using steam-methane reforming and methane splitting processes (i.e., "Gray" hydrogen) • A variety of additional processes are available to produce hydrogen from electricity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

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

Hydrogen Applications in Today's Economy

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

Forecasted U.S. Hydrogen Demand (million tons)



Key Hydrogen Terms and Implications for the Power Sector

Overview of Hydrogen Color Spectrum

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

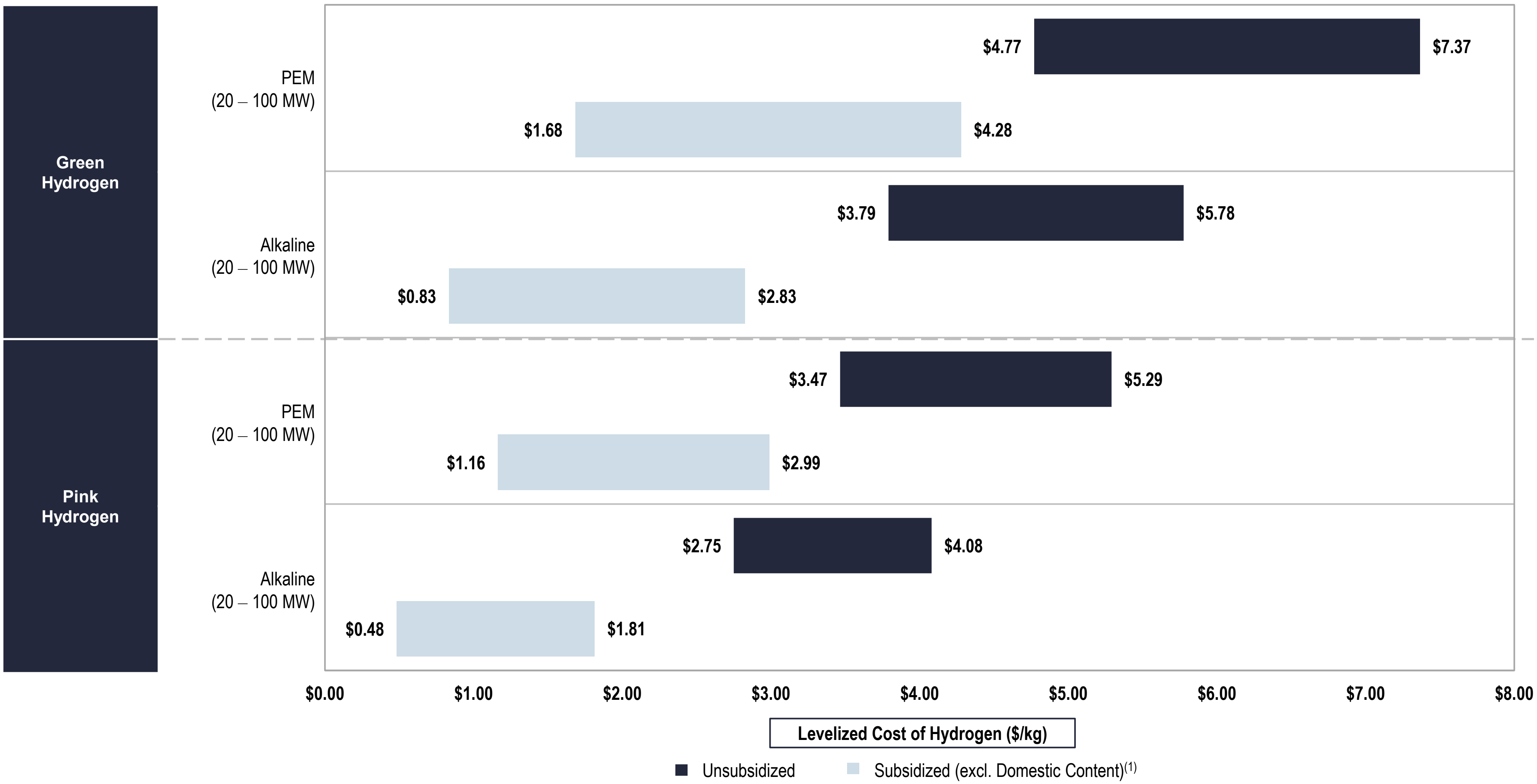
Implications for the Power Sector

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

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

Levelized Cost of Hydrogen Analysis—Illustrative Results

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



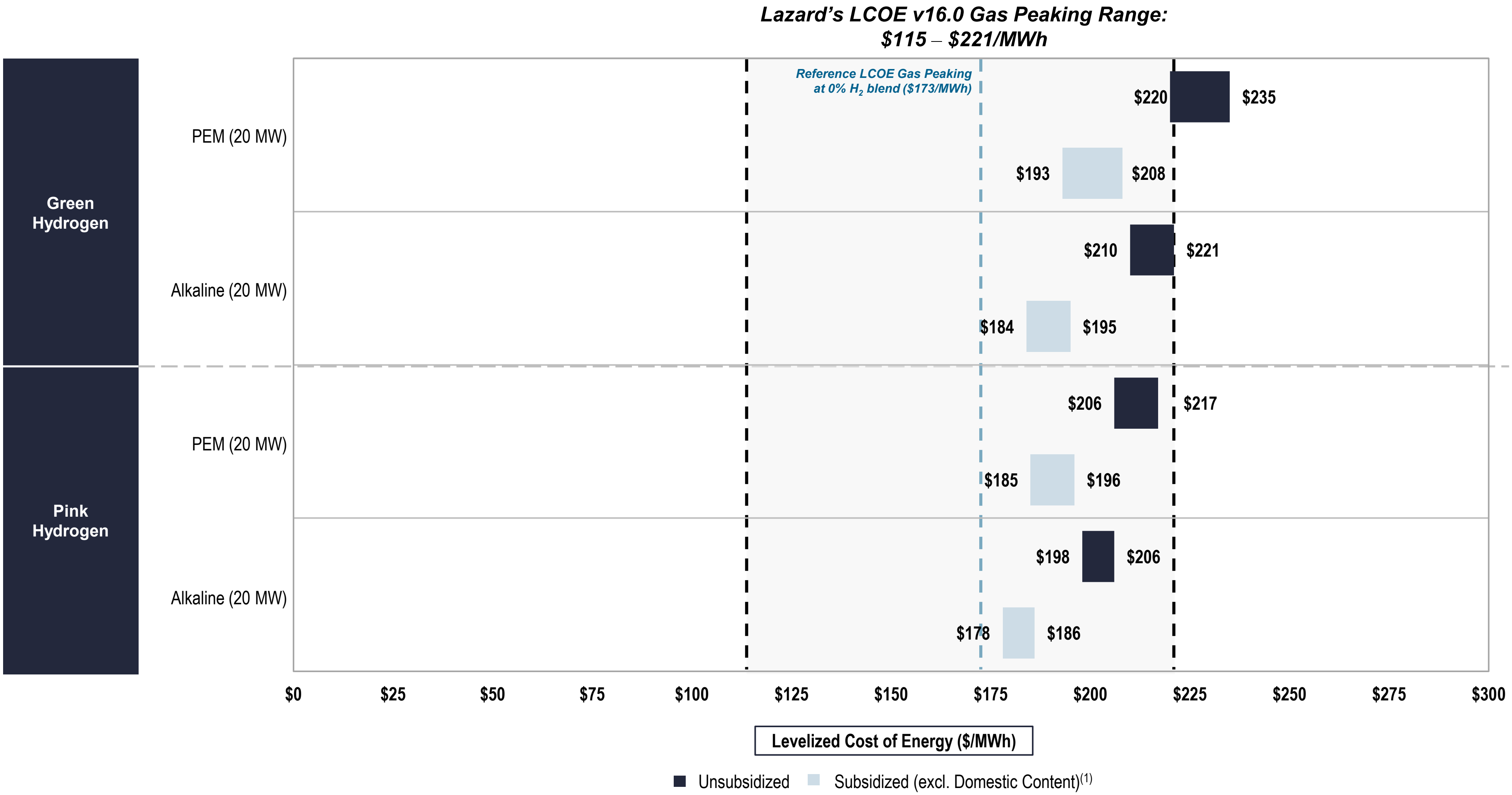
Source: *Lazard and Roland Berger estimates and publicly available information.*

Note: Here and throughout this presentation, unless otherwise indicated, this analysis assumes electrolyzer capital expenditure assumptions based on high and low values of sample ranges, with additional capital expenditure for hydrogen storage. Capital expenditure for underground hydrogen storage assumes $20/kg storage cost, sized at 120 tons for Green H_2 and 200 tons for Pink H_2 (size is driven by electrolyzer capacity factors). Pink hydrogen costs are based on marginal costs for an existing nuclear plant (see Appendix for detailed assumptions).

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

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

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



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

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

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

Appendix

A Maturing Technologies

Introduction

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

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

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

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

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

1 Carbon Capture & Storage Systems

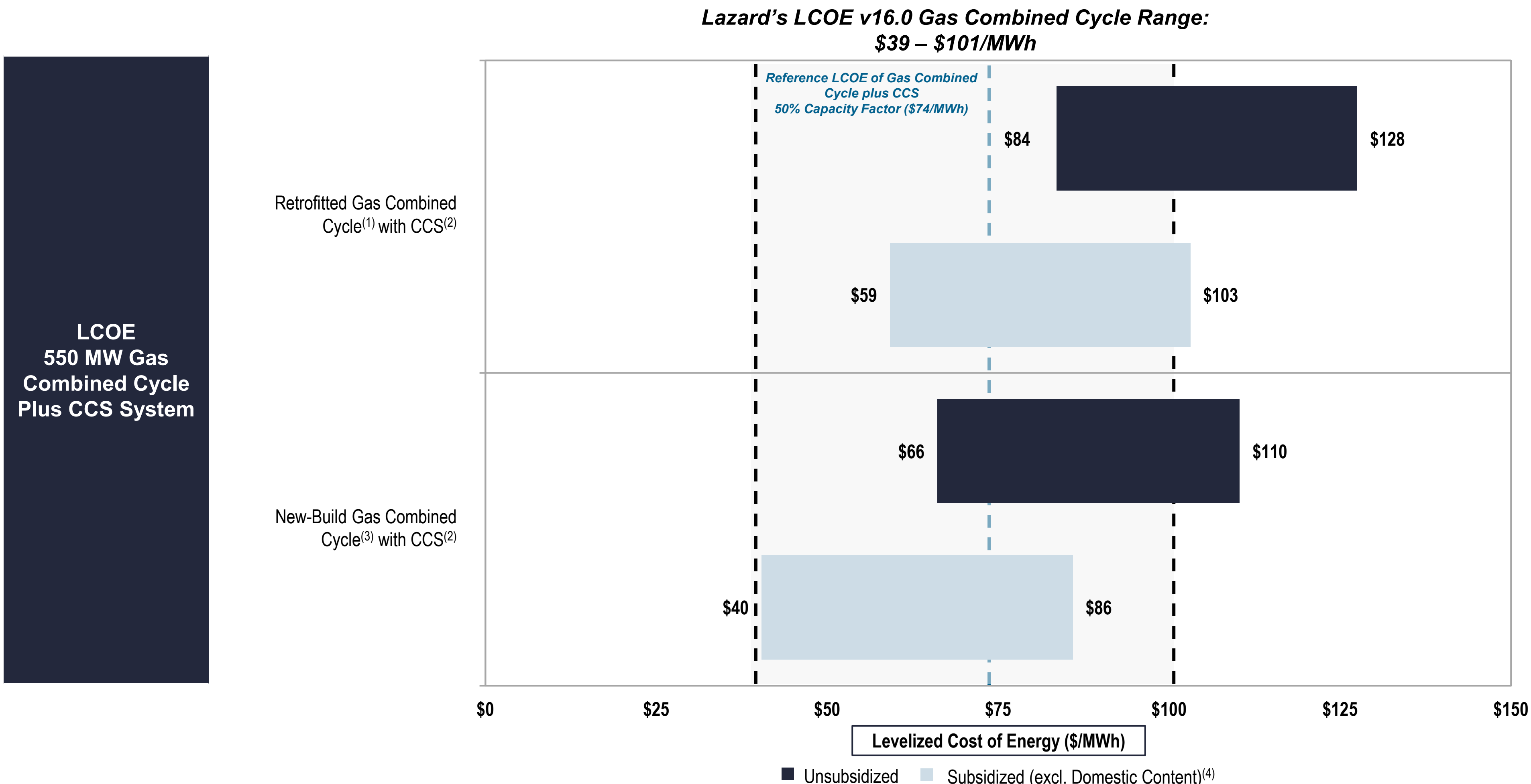
Lazard's Carbon Capture & Storage Analysis—Executive Summary

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

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

Levelized Cost of Energy—Gas Combined Cycle + CCS System

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



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

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

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

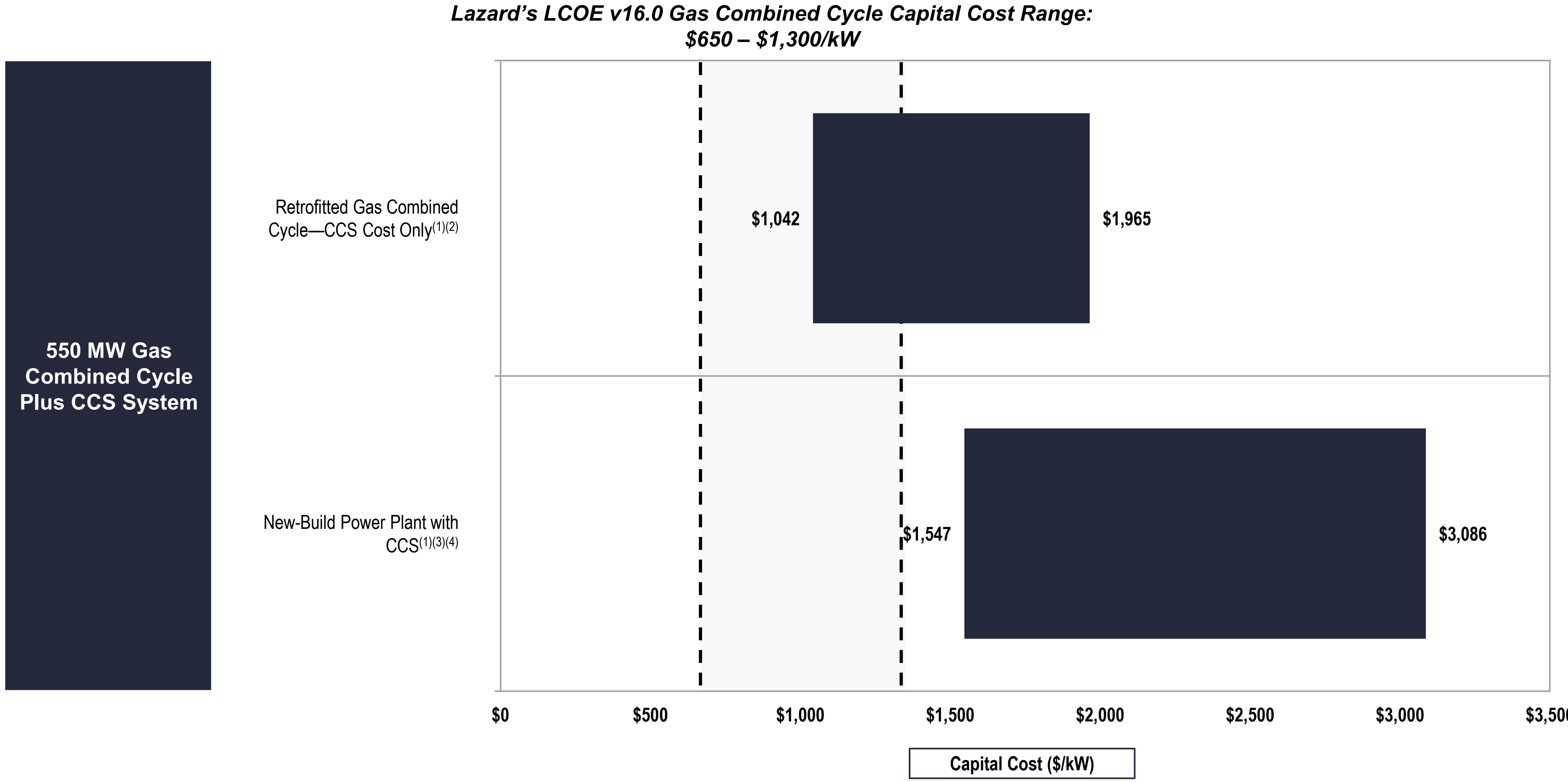
(2) Represents a 2 million-ton CO_2 plant and generation heat rate increases of 11% for the low case (85% capacity factor) and 21% for the high case (50% capacity factor) due to fixed usage of parasitic power by the CCS equipment.

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

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

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

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



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

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

2 Long Duration Energy Storage

Lazard's Long Duration Energy Storage Analysis—Executive Summary

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

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

Long Duration Energy Storage Technologies—Overview

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

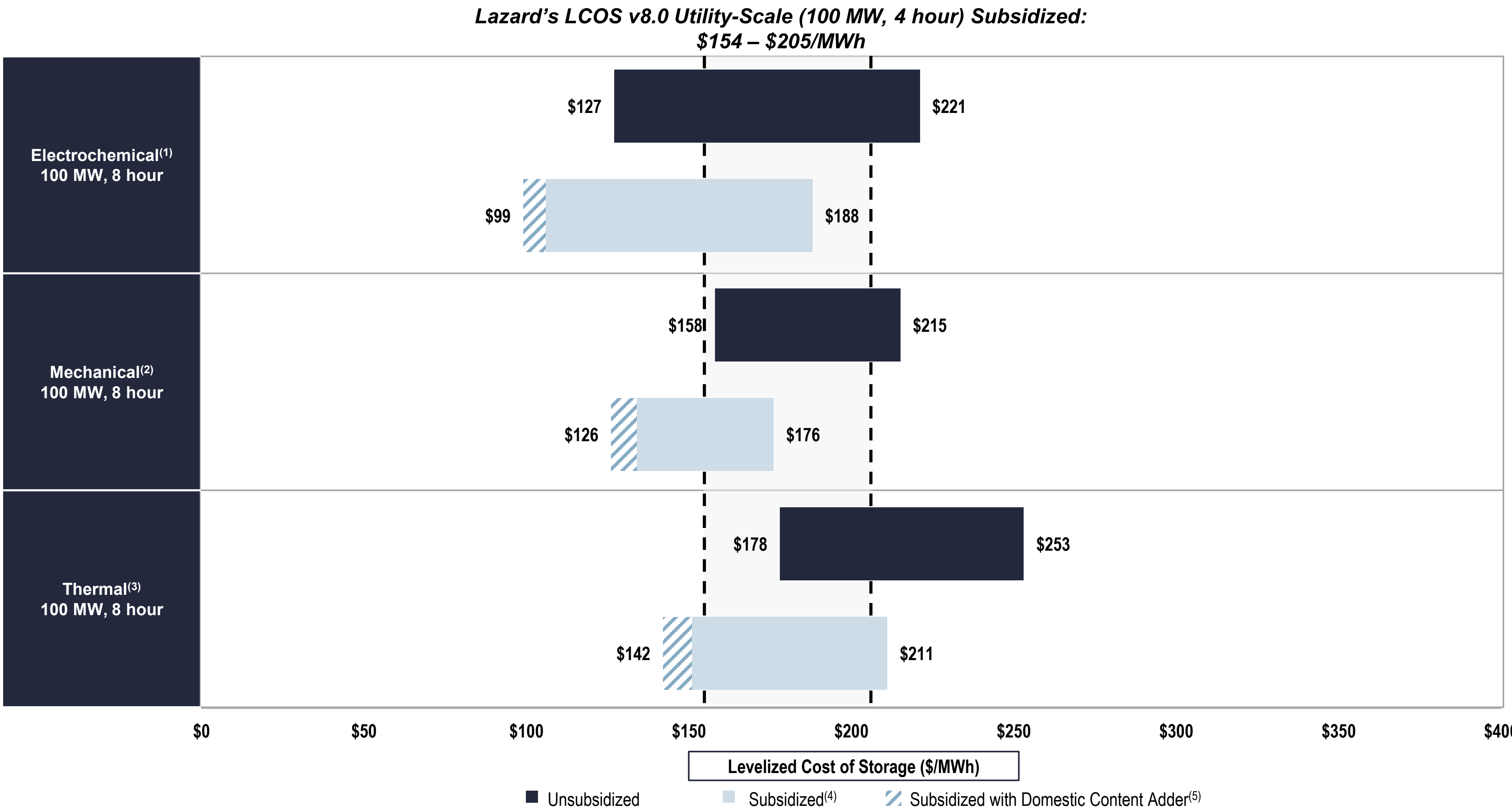
	Electrochemical	Mechanical	Thermal
Description	• Energy storage systems generating electrical energy from chemical reactions	• Solutions that store energy as a kinetic, gravitational potential or compression/pressure medium	• Solutions stocking thermal energy by heating or cooling a storage medium
Typical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

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

Attachment A

Levelized Cost of Energy—Illustrative LDES at Scale

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



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

Note: All cases assume a 20-year system life and 1 cycle per day at maximum depth-of-discharge.

(1) Electrochemical includes flow batteries (vanadium redox, zinc bromine) and non-flow (liquid metal).

(2) Mechanical includes CAES and liquified air energy storage ("LAES").

(3) Thermal includes sensible heat storage solutions (molten salt).

(4) This sensitivity analysis assumes that projects qualify for the full standalone storage ITC.

(5) This sensitivity analysis assumes the above and also includes a 10% domestic content adder. The IRA is comprehensive legislation that is still being implemented and remains subject to interpretation—important elements of the IRA are not included in our analysis and could impact outcomes.

Attachment A

APRIL 2023

B LCOE v16.0

LAZARD

Levelized Cost of Energy Comparison—Methodology

($ in millions, unless otherwise noted)

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

Unsubsidized Onshore Wind — Low Case Sample Illustrative Calculations

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

IRR For Equity Investors	**12.0%**

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

Technology-dependent

Levelized

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

Note: Onshore Wind—Low LCOE case presented for illustrative purposes only.

* Denotes unit conversion.

(1) Assumes half-year convention for discounting purposes.

(2) Assumes full monetization of tax benefits or losses immediately.

(3) Reflects initial cash outflow from equity investors.

(4) Reflects a "key" subset of all assumptions for methodology illustration purposes only. Does not reflect all assumptions.

(5) Economic life sets debt amortization schedule. For comparison purposes, all technologies calculate LCOE on a 20-year IRR basis.

Levelized Cost of Energy—Key Assumptions

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Attachment A

APRIL 2023

C LCOS v8.0

LAZARD

Levelized Cost of Storage Comparison—Methodology

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

Subsidized Utility-Scale (100 MW / 200 MWh)—Low Case Sample Calculations

Year[1]		*0*	*1*	*2*	*3*	*4*	*5*	*20*
Capacity (MW)	(A)		100	100	100	100	100	100
Available Capacity (MW)		110	109	106	103	100	110	102
Total Generation ('000 MWh)[2]	(B)*		63	63	63	63	63	63
Levelized Storage Cost ($/MWh)	***(C)***		***$178***	***$178***	***$178***	***$178***	***$178***	***$178***
Total Revenues	**(B) x (C) = (D)***		**$11.2**	**$11.2**	**$11.2**	**$11.2**	**$11.2**	**$11.2**
Total Charging Cost[3]	(E)		(4.4)	(4.5)	(4.6)	(4.7)	(4.8)	(6.3)
Total O&M, Warranty, & Augmentation[4]	(F)*		(0.3)	(0.3)	(0.6)	(0.6)	(4.3)	(0.8)
Total Operating Costs	**(E) + (F) = (G)**		($4.7)	($4.8)	($5.2)	($5.3)	($9.1)	($7.1)
EBITDA	**(D) - (G) = (H)**		**$6.5**	**$6.4**	**$5.9**	**$5.8**	**$2.1**	**$4.1**
Debt Outstanding - Beginning of Period	(I)		$11.7	$11.4	$11.2	$10.9	$10.5	$1.1
Debt - Interest Expense	(J)		(0.9)	(0.9)	(0.9)	(0.9)	(0.8)	(0.1)
Debt - Principal Payment	(K)		(0.3)	(0.3)	(0.3)	(0.3)	(0.3)	(1.1)
Levelized Debt Service	(J) + (K) = (L)		(1.2)	(1.2)	(1.2)	(1.2)	(1.2)	(1.2)
EBITDA	**(H)**		$6.5	$6.4	$5.9	$5.8	$2.1	$4.1
Depreciation (5-yr MACRS)	(M)		(9.9)	(15.9)	(9.5)	(5.7)	(5.7)	0.0
Interest Expense	(J)		(0.9)	2.8	0.0	(0.0)	0.0	0.0
Taxable Income	**(H) + (M) + (J) = (N)**		**($4.4)**	**($6.6)**	**($3.6)**	**$0.1**	**($3.6)**	**$4.1**
Tax Benefit (Liability)	**(N) x (Tax Rate) = (O)**		**$0.9**	**$1.4**	**$0.8**	**($0.0)**	**$0.8**	**($0.9)**
Federal Investment Tax Credit (ITC)	**(P)**		**$17.5**	**$0.0**	**$0.0**	**$0.0**	**$0.0**	**$0.0**
Capital Expenditures		**($46.7)**	**($11.7)**	**$0.0**	**$0.0**	**$0.0**	**$0.0**	**$0.0**
After-Tax Net Equity Cash Flow	**(H) + (L) + (O) + (P) = (Q)**	**($46.7)**[7]	**$23.7**	**$6.6**	**$5.5**	**$4.6**	**$1.7**	**$2.1**

IRR For Equity Investors	**12.0%**

Key Assumptions[5]	
Power Rating (MW)	100
Duration (Hours)	2
Usable Energy (MWh)	200
90% Depth of Discharge Cycles/Day	1
Operating Days/Year	350
Charging Cost ($/kWh)	$0.064
Fixed O&M Cost ($/kWh)	$1.30
Fixed O&M Escalator (%)	2.5%
Charging Cost Escalator (%)	1.87%
Efficiency (%)	91%
Capital Structure	
Debt	20.0%
Cost of Debt	8.0%
Equity	80.0%
Cost of Equity	12.0%
Taxes	
Combined Tax Rate	21.0%
Contract Term / Project Life (years)	20
MACRS Depreciation Schedule	5 Years
Federal ITC - BESS	30%
Capex	
Total Initial Installed Cost ($/kWh)[6]	$292
Extended Warranty (% of Capital Cost)	0.7%
Extended Warranty Start Year	3
Total Capex ($mm)	$58

Use-case specific

Global assumptions

Source: Lazard and Roland Berger estimates and publicly available information.
Note: Subsidized Utility-Scale (100 MW / 200 MWh)—Low LCOS case presented for illustrative purposes only.
* Denotes unit conversion.
(1) Assumes half-year convention for discounting purposes.
(2) Total Generation reflects (Cycles) x (Available Capacity) x (Depth of Discharge) x (Duration). Note for the purpose of this analysis, Lazard accounts for Degradation in the Available Capacity calculation.
(3) Charging Cost reflects (Total Generation) / [(Efficiency) x (Charging Cost) x (1 + Charging Cost Escalator)].
(4) O&M costs include general O&M ($1.30/kWh, plus any relevant Solar PV or Wind O&M, escalating annually at 2.5%), augmentation costs (incurred in years needed to maintain usable energy at original storage module cost) and warranty costs (0.7% of equipment, starting in year 3).
(5) Reflects a "key" subset of all assumptions for methodology illustration purposes only. Does not reflect all assumptions.
(6) Initial Installed Cost includes Inverter cost of $35/kW, Module cost of $188/kWh, Balance-of-System cost of $30/kWh and EPC cost of $30/kWh.
(7) Reflects initial cash outflow from equity sponsor.

Levelized Cost of Storage—Key Assumptions

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

x

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

Note: Assumed capital structure of 80% equity (with a 12% cost of equity) and 20% debt (with an 8% cost of debt). Capital cost units are the total investment divided by the storage equipment's energy capacity (kWh rating) and inverter rating (kW rating). All cases were modeled using 90% depth of discharge. Wholesale charging costs reflect weighted average hourly wholesale energy prices across a representative charging profile of a standalone storage asset participating in wholesale revenue streams. Escalation is derived from the EIA's "AEO 2022 Energy Source–Electric Price Forecast (20-year CAGR)". Storage systems paired with Solar PV or Wind do not charge from the grid.

Attachment A

APRIL 2023

D LCOH v3.0

LAZARD

Levelized Cost of Hydrogen Comparison—Methodology

($ in millions, unless otherwise noted)

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

Unsubsidized Green PEM—High Case Sample Illustrative Calculations

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

IRR For Equity Investors	**12.0%**

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

Technology-dependent

Levelized

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

Levelized Cost of Hydrogen—Key Assumptions

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

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

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

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

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

Attachment B

NAVIGANT RESEARCH

WHITE PAPER

What Is Driving Demand for Long Duration Energy Storage?

Commissioned by National Grid Ventures

Published 2Q 2019

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Section 1
INTRODUCTION

1.1 Defining Long Duration Energy Storage

A key feature of any energy storage system is its duration, which refers to the ratio between the system's maximum power output capacity in megawatts and its stored energy capacity in megawatt-hours. This metric indicates how long the system can discharge at full output capacity, and hence its relative value as a source of power. An energy storage system's duration also impacts its ability to provide grid services necessary to ensure reliability.

Navigant defines long duration energy storage as technologies capable of discharging at full power output for at least 5 hours. Currently available long duration storage technologies include pumped hydro storage, flow batteries, lithium ion (Li-ion) batteries, sodium sulfur batteries, power-to-gas, and compressed air energy storage (including liquid air storage).

Globally, installed energy storage capacity is approximately 156 GW, roughly 93% of which (144 GW) is pumped hydro storage. While the energy storage market has seen a significant increase in activity in the past 5 years, the majority of new energy storage projects offer relatively short duration output in the range of 1–4 hours. As such, there are limits to the grid services that these types of projects can provide, which will likely dampen demand for such projects in the long run as needs change.

Long duration energy storage systems play a key role in effectively integrating large amounts of renewable energy generation and ensuring that the overall operation of the grid is as efficient and reliable as possible.

1.2 Drivers of Demand for Long Duration Energy Storage

Integrating high percentages of renewable energy to a transmission grid has significant benefits in terms of reducing greenhouse gas emissions and helping to stabilize and lower energy costs, but it requires adapting the system to accommodate the characteristics of variable generation resources that may be located far from load. Long duration energy storage is uniquely suited to support this transition.

1.2.1 Grid Services

In addition to energy production, dispatchable fossil fuel generation has traditionally provided additional grid services that enhance reliability and stability. These grid services range from regulation service, which manages second-to-second imbalances in generation and load, to load following service, which meets daily ramps in demand.

While variable renewable energy resources like wind and solar are able to provide some grid services—especially shorter-term services like regulation—their intermittent nature limits their ability to fully replicate the longer duration system services like load following that fossil fuel generation provides. Although the grid impacts of adding renewable generation are relatively small at penetrations below 15%, above this level the loss of grid services from displaced fossil fuel generation creates a need for an alternate source.

Long duration energy storage can be used to shape and firm electricity from renewable sources so that it delivers a generation profile and grid services that are comparable to traditional fossil fuel generation during hours of peak demand.

An increasing number of jurisdictions (including California, Hawaii, and Washington) have set ambitious goals to reduce carbon emissions by sourcing 50% or even 100% of their electricity from renewable sources, creating a de facto demand for long duration energy storage facilities and the full suite of grid services they can provide.

1.2.2 Transmission Congestion

Transmission line congestion is an issue routinely faced by grid operators around the world, and can present particular challenges for renewable generation facilities, which are often located in areas far from load centers and served by inadequate regional transmission infrastructure. During periods of peak production, demand for transmission from remote renewable resources can exceed the capacity of the transmission grid to deliver that energy to load. At such times, the lack of transmission capacity will require utilities to curtail renewable generation, or turn to more expensive fossil generation resources located closer to load centers that can transmit energy over non-congested lines. In either case, the dollar and carbon cost of serving the load increases.

1.2.3 Renewable Energy Curtailment

In April 2019, California solar and wind farms curtailed 190,070 MWh of electricity, breaking previous records, according to the California Independent System Operator.

Curtailment refers to the practice of stopping renewable energy production at times when supply exceeds demand, as well as when there is insufficient transmission capacity to deliver electricity to load centers, as discussed above. Curtailment is already occurring in markets with moderate penetrations of variable renewable energy, such as the central US, where abundant wind generation at night often exceeds demand, and midday in places such as Australia, California, and Hawaii, where solar photovoltaic generation outstrips consumption. Notably, in the month of April 2019, 190,070 MWh of electricity from California solar and wind farms was curtailed, breaking previous records. This curtailment trend is increasing substantially as California adds 1,500 MW–2,000 MW of solar (both rooftop and utility scale) to its grid every year.

Transmission congestion and variable renewable energy curtailment result in lower clean energy production and higher greenhouse gas emissions. By storing large amounts of energy for dispatch when transmission capacity is available, long duration energy storage offers an effective way to support high percentages of renewable generation and optimize the use of transmission assets, resulting in a more efficient electricity system.

1.2.4 The Limitations of Competing Storage Technologies

Additional drivers of demand for long duration energy storage are the limitations of existing battery technologies, and particularly those of Li-ion batteries, which include concerns about their relatively short lifespan and safety, as well as the availability of raw materials, security of the supply chain, and their environmental impact, topics that will be addressed in more detail in a subsequent white paper.

1.2.4.1 Lifespan

The lifespan of a battery is expressed in terms of the number of times it can be charged and discharged, which is referred to as a cycle. The cycle life of Li-ion batteries varies depending on the specific sub-chemistry used, and ranges from as low as 500 cycles for the least expensive Li-ion technologies to up to 10,000 for the most expensive, which translates into a 3–15-year lifespan depending on the application for which it is used. This is relatively short in the context of grid applications, so it is typical to extend a Li-ion battery's life by replacing or augmenting its capacity when performance degrades. While these strategies can be effective, they also result in significantly higher operation and maintenance costs.

1.2.4.2 Safety

As with cycle life, different Li-ion chemistries vary in terms of safety profiles. More expensive and robust battery chemistries like lithium iron phosphate and lithium titanite oxide have strong safety records, while less expensive chemistries typically do not. Although significant advances have been made to improve the safety of large-scale stationary Li-ion batteries, instability and thermal runaway remain significant concerns in the industry. Numerous fires at large Li-ion battery energy storage facilities in 2018 and 2019 have highlighted these concerns and resulted in increasingly restrictive fire safety codes in jurisdictions around the world. The potential for safety incidents such as these serve to highlight the value of other long duration energy storage technologies that are inherently safer.

1.2.5 Resilience

Longer storage durations equate to the ability to provide backup power for a longer period, which is a major driver of interest in long duration storage. Furthermore, many long duration technologies such as pumped hydro storage, flow batteries, and compressed air do not have the same restrictions on cycle life as Li-ion and other batteries, thereby providing greater flexibility and resilience.

Section 2

THE ROLE OF LONG DURATION ENERGY STORAGE ON THE GRID

2.1 Reliable and Dispatchable Capacity

Long duration energy storage is essential to a grid that relies heavily on variable renewable generation, because it makes it possible to align supply with demand, and it can provide grid services historically offered by conventional fossil fuel power plants.

2.1.1 Matching Renewable Energy Supply with Demand

Unlike dispatchable fossil fuel facilities, renewable energy generation depends on resource availability, and periods of peak production may not align with periods of peak demand. The ability to store large amounts of renewable energy for release during periods of high demand may emerge as one of the most essential applications for long duration energy storage in the long term and is a particularly attractive benefit in areas that experience high levels of wind power curtailment at night, or solar curtailment during the day.

2.1.2 Reserves and Capacity

Reserves and capacity are services that help ensure the reliability of the grid by helping operators meet variations in electricity supply and demand. These grid services, which have traditionally been provided by conventional thermal generators, include spinning reserves, non-spinning reserve capacity, and load following.

Variable renewable energy resources like wind and solar can provide some grid services, but their non-dispatchable nature limits their ability to do so on a reliable basis. Similarly, shorter duration energy storage technologies are well suited for short duration ancillary services, but not for providing dispatchable capacity over periods longer than 5 hours. Reserve and capacity assets are often called upon for extended periods of time due to plant outages, extreme weather, and other issues.

As renewables gradually displace fossil fuel generation, the need for technologies that can economically provide a full suite of grid services will increase. Replacing most or all of a system's fossil fuel baseload and peaking power plants with renewable energy will require pairing these resources with long duration, large-scale energy storage.

2.3 Transmission Optimization

As discussed in Section 1.2, large-scale renewable facilities are often located in remote areas with limited access to transmission lines. At times of peak production, these lines can become congested, forcing renewable generators to curtail their output, and resulting in the loss of clean energy as well as revenue losses for the generator and reduced energy security.

Long duration energy storage located at strategic points in the grid can be used to address this by saving renewable energy for release at times when transmission lines are less congested. Doing so improves the functionality of existing transmission infrastructure, making it possible to efficiently integrate new resources while postponing the need for costly transmission upgrades.

Section 3
CASE STUDIES

3.1 Pumped Hydro Storage in Europe

Long duration energy storage already serves as a critical resiliency resource for power systems with high percentages of renewable energy, notably on islands such as El Hierro in the Canary Islands and Kauai in Hawaii. However, long duration energy storage also plays a key role in the operation of much larger electricity grids.

Germany's power system is the largest in Europe and boasts more than 100 GW of wind and solar generation capacity. Under the Energiewende (energy transition) policy, the country aims to generate 35% of its electricity from renewables by 2020, rising to 80% by 2050. Achieving this will require new investments that may include additional transmission infrastructure, interconnections with neighboring countries, and energy storage.

While Germany has seen major growth in its battery energy storage market, most of this activity has been focused around short duration systems for grid stability services and residential customers integrating solar power. When it comes to effectively integrating over 100 GW of renewable generation, pumped hydro systems in Germany and neighboring countries are the long duration energy storage technology of choice.

These resources support the German energy transition by storing excess electric generation from variable renewable sources and dispatching it as needed to provide reliable capacity during periods of peak demand or reduced production. As the country moves toward increasingly higher percentages of renewables, new pumped hydro storage projects are being explored.

Germany's use of pumped hydro storage may provide a useful point of comparison for energy planners in the US. As an example, California has 30 GW of installed solar and wind, and the ability to leverage the long duration energy storage benefits of pumped hydro storage projects both in California and the Pacific Northwest.

3.2 Potential Capacity Shortages in the Western US

3.2.1 Pacific Northwest

In the US Pacific Northwest, a transition to a heavy reliance on renewable generation is underway and gaining momentum. Oregon has set ambitious carbon-reduction goals, and Washington recently passed legislation mandating that by 2030, 80% of electricity sold in the state must be carbon free.

Achieving these targets will require a major increase in variable renewable generation sources like solar and wind. According to the consulting and analytics firm E3, load growth and the replacement of retired fossil fuel power plants with renewable generation could result in an 8 GW capacity deficit in the US Pacific Northwest by 2030 unless new dispatchable capacity resources are developed.

Washington's legislation will impact Puget Sound Energy, Avista, and PacifiCorp, all of which own shares of the Colstrip 3 and 4 coal plants. If the move to decarbonize Washington's energy supply leads to the Colstrip facilities closing in 2025 rather than their current planned retirement in 2035, it will add another 1.5 GW to E3's projected 8 GW capacity deficit in 2030. An additional impact of the legislation is that after 2030, these utilities will need to offset any carbon emissions associated with the use of gas-fired resources for commercial energy transactions.

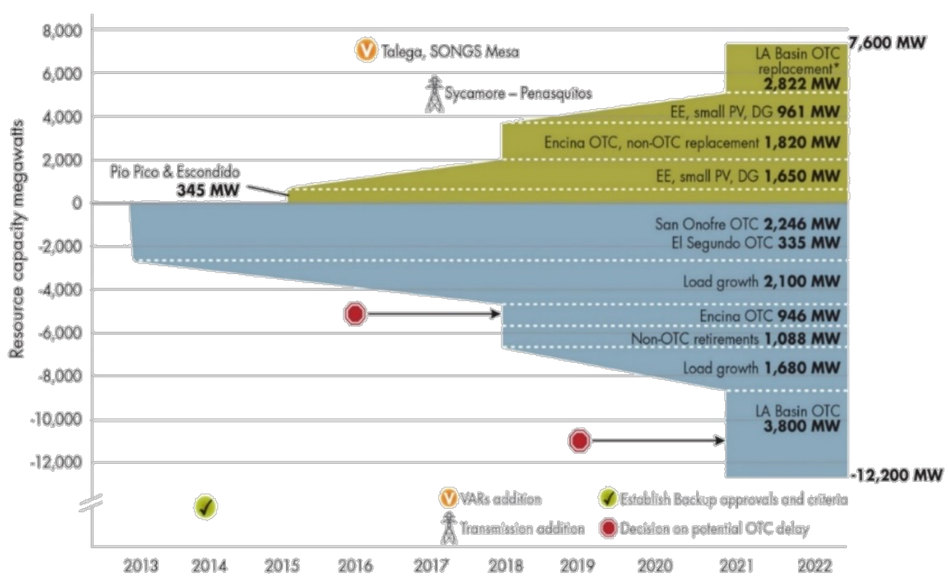
While the region has sufficient renewable energy resources to meet electricity demand, long duration energy storage technologies will have an important role in to play in providing the replacement capacity needed to ensure grid stability.

3.2.2 California

California has benefited from significant surplus capacity and energy from the Pacific Northwest for many years, but the magnitude of the anticipated capacity requirements described above will likely decrease capacity and energy available for export to California entities between 2020-2030.

California has set a target of getting 100% of its energy from carbon-free sources by 2045 (with at least 60% of supply from eligible renewable resources). Similar to the situation in the Pacific Northwest, as shown in Figure 3-1, as the state's renewable energy capacity increases, fossil fuel power plants are being retired, resulting the loss of dispatchable capacity they provide. According to the California Independent System Operator (CAISO), up to 9.6 GW of natural gas-fired generation may be retired for economic reasons, and if even 4 GW (or less) of natural gas comes offline, the state could see load following shortfalls.

Figure 3-1. Electrical Capacity Retirement and Additions Forecasts, California Independent System Operator: 2013–2022



(Source: California Independent System Operator)

California already receives resource adequacy and capacity services from both standalone energy storage and renewable-plus-storage projects, with most storage projects having a 4-hour duration. In the long run, CAISO has predicted that as more thermal resources retire, reliability requirements may mean that demand for longer duration energy storage increases.

Long duration energy storage has a particularly important role to play in California, which faces a dual challenge of excess generation from solar during the day, and a steep increase or ramp in demand in the evening hours. Part of this increase in demand is caused by the charging of electric vehicles, the numbers of which are expected to grow dramatically over the next decade.

California has recently experienced winter 3-hour ramps of as much as 14,000 MWh. Long duration energy storage can store excess solar generated during the day and release it to meet the evening ramp.

Section 4
CONCLUSION

The transition to greater reliance on variable renewable generation is creating a need for expanded energy storage infrastructure in power grids around the world. It is important to recognize that different energy storage technologies offer features that make them best suited for different applications.

Short duration technologies are ideally suited for providing grid stability services and smoothing small fluctuations in renewable generation output. In contrast, long duration storage technologies like pumped hydro storage are uniquely able to stand in as a direct replacement for the bulk capacity reserves and other grid services provided by fossil fuel generators.

Grid operators managing systems as small as the island grids of El Hierro and the Hawaiian Islands, and as large as those of European countries have already recognized the value of longer duration energy storage as they make the transition to high levels of renewable energy.

To successfully follow suit, US grid operators charged with ensuring the reliability of their system under ambitious decarbonization goals will need to have both long and short duration energy technologies at their disposal.

Section 5

ACRONYM AND ABBREVIATION LIST

CAISO .... California Independent System Operator

GW .... Gigawatt

GWh .... Gigawatt-hour

Li-ion .... Lithium Ion

MW .... Megawatt

MWh .... Megawatt-hour

US .... United States

Section 6
SCOPE OF STUDY

This white paper examines the market for long duration energy storage technologies on the power grid. Specific attention is paid to the drivers of long duration energy storage, the role for long duration energy storage on the grid, and case studies that illustrate the convergence of these issues. Navigant Research prepared this white paper to provide an independent analysis of the opportunities for long duration energy storage. This white paper does not consist of any endorsement of any specific technology, project, or company. Rather this paper provides readers with an understanding of the market for long duration storage and why it will be required for a future grid reliant on renewable energy generation.

Published 2Q 2019

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Attachment B

NAVIGANT
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WHITE PAPER

Comparing the Costs of Long Duration Energy Storage Technologies

Commissioned by National Grid Ventures

Published 2Q 2019

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Section 1
INTRODUCTION

This white paper is the second in a three-part series exploring long duration energy storage technologies for the power grid. The first paper examined the factors driving the need for long duration energy storage and the role it plays on the grid. In this second paper, the installation and operating costs of the five competing long duration energy storage technologies are explored in greater detail. The third and final paper in the series will discuss other non-monetary factors that should be considered when evaluating energy storage technologies.

1.1 Utility-Scale Long Duration Energy Storage Technologies

The utility-scale energy storage market encompasses a range of technologies with differing operating characteristics, strengths, and weaknesses. Some technologies are best suited to provide short-duration grid stability services including frequency regulation and voltage support. Such technologies include flywheels, ultracapacitors, and certain lithium ion (Li-ion) chemistries. Other technologies like pumped hydro storage (PHS) or compressed air energy storage (CAES) systems are best designed for large-scale long duration bulk energy storage. The following sections introduce the five most prevalent technologies competing in the long duration energy storage market.

1.1.1 Pumped Hydro Storage

PHS has traditionally been the technology of choice for delivering long duration storage services. It is the most mature and the largest capacity storage technology available, and currently provides approximately 93 percent of global operational electricity storage capacity. PHS facilities pump water from one reservoir into another at a higher elevation, typically using lower priced off-peak or surplus renewable electricity. When energy is required, the water in the higher elevation reservoir is released and runs through hydraulic turbines that generate electricity. PHS plants typically have a round-trip efficiency of 75–80 percent.

> *A key feature of any energy storage system is its* ***discharge duration****, which refers to the ratio between the system's maximum power output capacity in megawatts and its stored energy capacity in megawatt-hours.*

PHS technology has evolved over the years. Variable speed pumps represent the latest generation of the technology and provide significant advantages. A variable speed pump turbine can be regulated to plus or minus 20 percent of capacity during a pumping cycle, which provides the ability to accurately follow changes in both load and the supply of fluctuating renewable generation. In addition, variable speed PHS facilities can be designed to transition rapidly between pumping and generating. This flexibility, combined with large storage capacity, means that PHS facilities offer grid operators capabilities that are critical to managing high penetrations of renewables and aligning variable renewable energy supply with shifts in load.

1.1.2 Compressed Air Energy Storage

CAES systems compress ambient air, store it under high pressure conditions, and then release it to power generator-tied turbines when electricity is needed. The largest barrier to CAES development arises from geographical restrictions because the systems require either natural underground caverns or underground tanks, which are rarely in convenient locations. CAES systems are advantageous for the purposes of large-scale storage because they typically range from 50 MW to 300 MW of power output and can be brought to full output in around 10 minutes. However, CAES systems have relatively low round-trip efficiencies, ranging from only 48 percent for older designs to as high as 75 percent for more modern systems. There are only two large-scale CAES plants in operation—one in the US state of Alabama and one in Germany, with durations of 26 and 4 hours, respectively.

1.1.3 Flow Batteries

Flow batteries are single-celled batteries that transform the electron flow from activated electrolyte into electric current. They achieve charge and discharge by pumping a liquid anolyte and catholyte across a membrane. While there are many different flow battery chemistries, the vanadium redox chemistry has emerged as the market's leading technology. The round-trip efficiency for flow batteries ranges from 65–85 percent.

> ***Round trip efficiency*** *refers to the difference between the amount of energy that is stored, and the amount of energy available for discharge. If a battery is charged with 100 kWh, but provides 75 kWh of energy when discharged, it has a round trip efficiency of 75 percent.*[1]

Flow batteries have several inherent advantages over other battery technologies. Their discharge duration is correlated to the volume of electrolytes stored, so storage can be increased simply by adding additional tanks of electrolyte, with limited marginal costs. The technology is also generally safer than Li-ion or molten salt batteries—the use of nonflammable electrolytes means that most flow battery systems do not present a fire safety hazard. However, the electrolytes used in most flow batteries are corrosive and may be an environmental hazard if spilled. Furthermore, flow batteries experience little to no depletion of active materials over time, giving them greater cycle life expectancies (10,000+ cycles) than other battery types.

[1] Hennessy, Tim, "Calculating the True Cost of Energy Storage," *Renewable Energy World*, January 12, 2015.

1.1.4 Molten Salt Batteries

Molten salt batteries include sodium sulfur (NaS) and sodium-metal halide (NaMx) systems, both of which use a molten sodium anode and a solid beta-alumina electrolyte at high operating temperatures of about 300°C or more. Typical performance characteristics of NaS and NaMx batteries are relatively similar with regard to high energy density, long cycle life, and moderate-to-high round-trip efficiencies of 75–90 percent.

Molten salt batteries gained traction in the market early on, but the battery storage market has shifted heavily toward Li-ion technologies. This is because molten salt batteries' performance characteristics and high price point (which is driven by expensive beta-alumina membranes) make them better suited for long duration applications, while the energy storage industry has recently focused largely on short-duration applications.

1.1.5 Lithium Ion Batteries

Li-ion batteries use the flow of lithium ions between the cathode and anode of the battery to charge and discharge. Li-ion batteries have excelled as the primary chemistry of choice in consumer electronics for the last decade, and are now finding a limited role on the grid.

In general, Li-ion batteries have excellent energy and power densities and round-trip efficiency. However, as discussed in Section 2, their average duration of 4 hours limits their ability to support the integration of high percentages of renewable energy. A more thorough exploration of this issue is presented in the first white paper in this series, *What Is Driving Demand for Long Duration Energy Storage?*[2]

The relatively short cycle life of Li-ion batteries, which can range from 500 to 10,000 cycles depending on usage and the specific Li-ion chemistry that is used, translates into a 3–15-year lifespan. This makes Li-ion batteries an expensive choice for long-term grid applications.

In the context of energy storage systems, one sequence of charging and discharging is referred to as a ***cycle****. A system's* ***cycle life*** *refers to the number of times it can cycle or be charged and discharged before it degrades and becomes inoperable or unusable for a given application.*

[2] Navigant Research and National Grid Ventures, *What Is Driving Demand for Long Duration Energy Storage?* SL Energy Storage, 2Q 2019, https://www.slenergystorage.com/resources.html.

Section 2

LONG DURATION ENERGY STORAGE TECHNOLOGIES: FACTORS TO CONSIDER WHEN EVALUATING COSTS

2.1 Comparing Apples to Oranges: Varying Characteristics and Costs

The five major long duration energy storage technologies discussed in this paper differ widely in terms of their operational benefits, cost structure, typical project scale, and development timelines. This section provides an overview of key points of comparison.

2.1.1 Discharge Duration

Discharge duration refers to the length of time an energy storage system can discharge at full output capacity. While all five major long duration energy storage technologies are capable of long duration discharge, they vary considerably in their range of duration. Table 2-1 lists the average discharge duration for each of these technologies.

Table 2-1. Average Discharge Duration Assumptions, Long Duration Energy Storage Technologies

Technology	Average Duration
CAES	3–24 hours
Flow Battery	2–12 hours
Lithium Ion Battery	0.5–8 hours
Molten Salt Battery	6–7 hours
Pumped Hydro Storage	6–24 hours

(Source: Navigant Research)

Although Li-ion battery projects can be designed to have a duration of up to 8 hours, most operational Li-ion batteries have durations of 4 hours or less. This places them at the low end of the duration range and limits their ability to offer a full suite of grid services. At the other end of the spectrum, PHS projects have average durations that range from 6 to 24 hours, with some plants designed to discharge at full power for longer than 24 hours. This duration enables them to replicate the grid and reliability services provided by conventional power plants.

2.1.2 Project Scale and Development Timelines

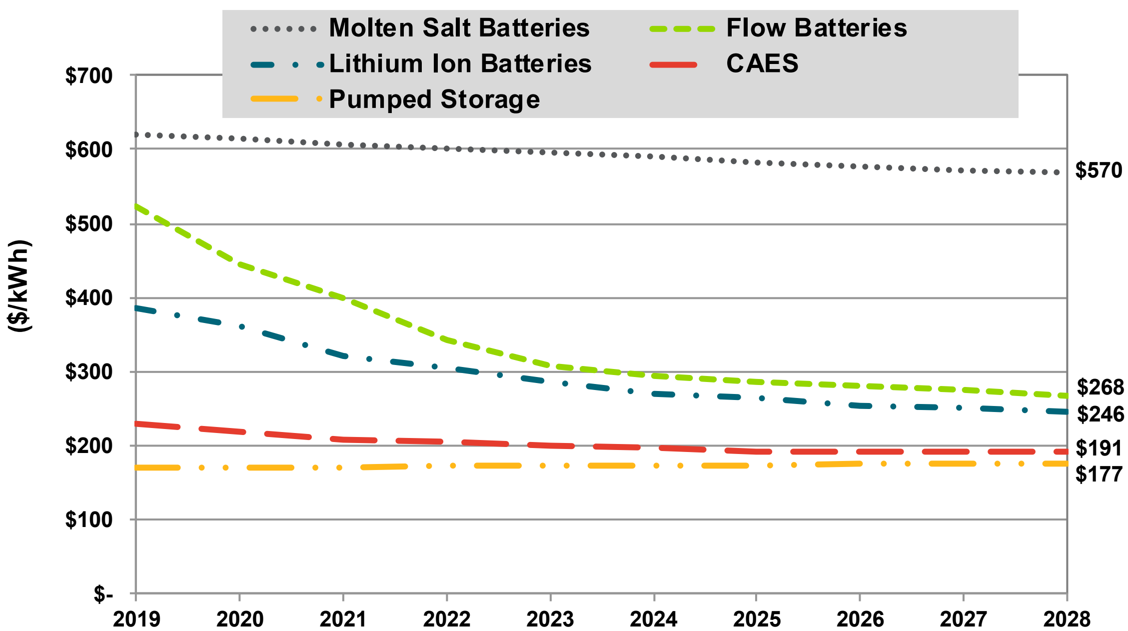
Long duration energy storage technologies can vary greatly in their scale and development timelines, with corresponding impacts on upfront costs. While battery projects can be deployed more quickly at a lower initial cost they are often smaller in scale, averaging 5–50 MW in capacity. In contrast, PHS and CAES facilities are typically large-scale plants that provide 100 MW of capacity or more, requiring significant upfront investment and longer lead times.

The scaling of duration and total project cost also varies considerably between technologies. For Li-ion battery projects, scaling to longer durations requires adding more battery packs, which represent the largest cost component of the project. Increasing duration results in an essentially linear increase in costs. By comparison, larger scale technologies such as PHS have different cost structures. Much of the cost to build a PHS project is fixed, coming from land development and construction. Scaling a PHS plant to longer durations requires only increasing the volume of the reservoirs being used, which has a relatively small impact on total system cost relatively to construction and development expenses.

2.1.3 Upfront Installed Costs versus Lifetime Costs

Long duration energy storage technologies have a wide range of installed costs, which are typically noted in dollars per kilowatt-hour of stored energy capacity. Navigant Research expects total upfront installed cost for each of the major technologies to range from $170.3/kWh for PHS to $619.7/kWh for molten salt batteries, as illustrated by Chart 2-1.

Chart 2-1. Average Utility-Scale Bulk Energy Storage System Installed Cost (CAPEX) by Battery Technology, World Markets: 2019-2028



(Source: Navigant Research)

The falling upfront costs of Li-ion batteries have made them attractive for some grid applications, but they have a short lifespan compared to conventional generation assets and PHS facilities, which are typically designed to last for several decades. The average lifespan of a Li-ion battery storage system ranges from 3–15 years depending on how it is used and how the specific Li-ion chemistry employed. While the inevitable degradation of Li-ion systems can be addressed by replacing depleted battery modules over time, this practice increases lifetime project costs considerably. These and other considerations are explored in Section 3.

Section 3

ACCURATELY COMPARING THE COST OF ENERGY STORAGE TECHNOLOGIES

3.1 Comparing Apples to Apples: Levelized Cost of Storage

When evaluating energy storage technology options, it is critical that grid operators and regulators consider key pieces of the energy storage cost puzzle beyond upfront cost. A levelized cost of storage (LCOS) calculation can be used to more accurately evaluate the lifetime costs of different technologies and yield cost per megawatt-hour figures that support fair and valid comparisons.

Lazard has conducted extensive evaluations of energy storage technologies and applications. The advisory firm has developed a method for calculating LCOS that is perhaps the most robust comparison of the true cost to own and operate different storage technologies.

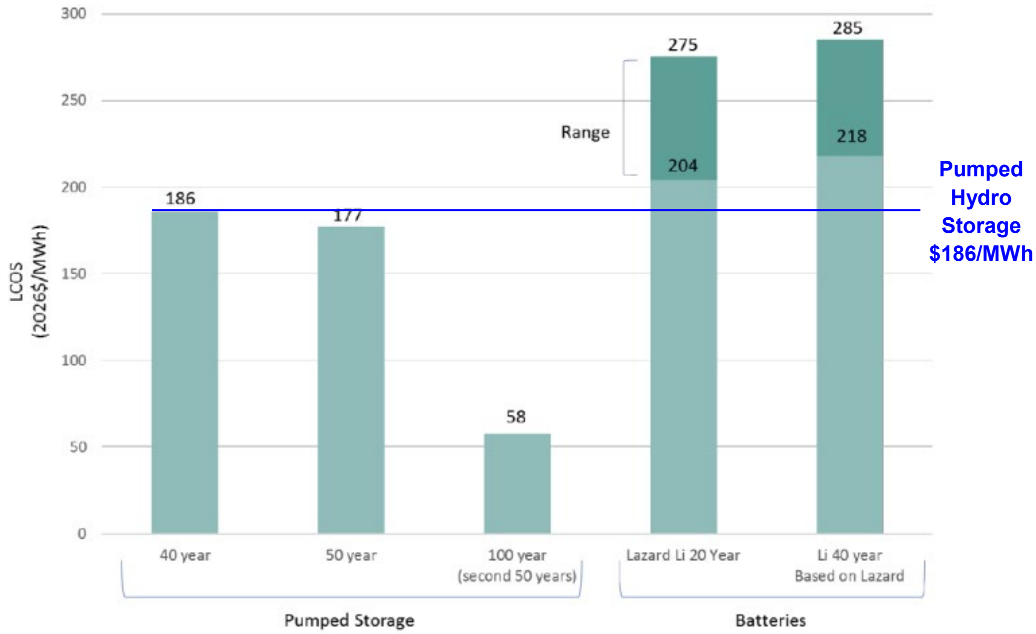
Lazard's LCOS calculation factors in the upfront investment required for a given storage technology. The calculation also incorporates operating patterns (cycles per day/year) for a given application, depth of discharge, round-trip efficiency, annual operations and maintenance costs, equipment replacement costs, system charging costs, and the overall useful life to yield an estimate for the cost per megawatt-hour, thereby enabling an apples-to-apples comparison.

Figure 3-1 illustrates the stark contrast in the LCOS for PHS and Li-ion batteries over similar time periods based on PHS project evaluation conducted by the San Diego County Water Authority.[3] PHS projects are designed for up to 50 years of operation with limited equipment replacement, a lifespan that can be extended to 100 years with proper maintenance and component replacements. By comparison, Li-ion battery projects typically have much shorter lifespans, although it is possible to keep them operating for 20 or even 40 years with proper maintenance and battery replacement.

[3] Victor, David G, et al., *Pumped Energy Storage: Vital to California's Renewable Energy Future*. San Diego County Water Authority, 2019, *Pumped Energy Storage: Vital to California's Renewable Energy Future*, www.sdcwa.org/sites/default/files/White Paper - Pumped Energy Storage V.16.pdf.

As shown, these differences in operating life result in significantly higher levelized costs for Li-ion batteries. Using projected costs for facilities with a commercial operation date of January 1, 2026, over a 40-year operating life, PHS facilities have an LCOS of $186/MWh, compared to $285/MWh for Li-ion battery facilities for the same period.

Figure 3-1. Levelized Cost of Storage Comparison, Pumped Hydro Storage versus Li-ion Batteries



(Source: Lazard and San Diego County Water Authority)

Section 4
CONCLUSION

This report highlights several factors that can affect the true cost of different long duration energy storage technologies. In addition to the upfront costs to build a new project, the required operating costs and expected lifespan of each storage technology must also be considered.

While the falling upfront costs of Li-ion battery storage systems have attracted a lot of attention and increased the competitiveness of small to midsized battery projects, a more holistic view of total project costs shows that PHS and CAES deliver much better economics for ratepayers.

This white paper expands on the topic of long duration energy storage introduced in the first paper in this series. In addition to the financial considerations for each long duration technology presented in this report, there are many non-financial issues surrounding these technologies that must be considered when comparing technologies. These issues, including the safety, sustainability, and long-term reliability of battery energy storage technologies, will be explored in the third white paper in the series.

Section 5
ACRONYM AND ABBREVIATION LIST

CAES....................Compressed Air Energy Storage

kWh....................Kilowatt-hour

LCOS....................Levelized Cost of Storage

Li-ion....................Lithium Ion Battery

MW....................Megawatt

MWh....................Megawatt-hour

NaMx....................Sodium-Metal Halide Battery

NaS....................Sodium Sulfur Battery

PHS....................Pumped Hydro Storage

US....................United States

Section 6
SCOPE OF STUDY

This white paper examines the market for long duration energy storage technologies on the power grid. Specific attention is paid to the differences among technologies in terms of operational characteristics, lifetime, and project cost. Navigant Research prepared this white paper to provide an independent analysis of the opportunities for long duration energy storage. This white paper does not consist of any endorsement of any specific technology, project, or company. Rather, this paper provides readers with an understanding of technologies competing in the market for long duration storage and how they compare to one another.

Published 2Q 2019

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Note: Editing of this report was closed on June 26, 2019.

Attachment B

NAVIGANT
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WHITE PAPER

Betting on Batteries?

Commissioned by National Grid Ventures

Published 3Q 2019

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Section 1

INTRODUCTION

1.1 Evaluating Energy Storage Options

This white paper is the third in a three-part series exploring long duration energy storage technologies. The first paper discussed why long duration energy storage is critical to the successful integration of large amounts of renewable energy, and how it will play a major role in the transition toward a more sustainable, reliable, and efficient electrical grid. The second paper explored the installation and operating costs of the five commercial long duration energy storage technologies. It notes that, with 144 GW installed worldwide, pumped hydro storage accounts for 93 percent of global energy storage capacity and is the most cost-effective option both today and in the long run. By comparison, lithium ion (Li-ion) battery storage has a relatively small market share, with 4.3 GW of installed capacity that accounts for 2.4% globally.

Li-ion batteries offer some advantages that make them the best choice of energy storage technology for certain applications, and ultimately, decarbonizing the electrical grid through the addition of large amounts of intermittent renewable energy sources will necessitate an "all of the above" approach to energy storage.

Decarbonizing the electrical grid through the addition of large amounts of intermittent renewable energy sources will necessitate an "all of the above" approach to energy storage.

However, Li-ion batteries have several disadvantages related to safety, environmental, and supply chain that should be factored into evaluations of energy storage options. These concerns are the focus of this third and final paper in the series.

1.2 The Global Market for Utility-Scale Energy Storage

The global market for utility-scale energy storage is expected to reach 155 GW in 2019, a figure that is predicted to increase to 271.5 GW by 2025. A small number of countries account for the majority of new utility-scale energy storage project capacity. In 2019, it is expected that the top 10 countries will account for 1,242 MW of new capacity, representing approximately 80 percent of the global market for the year. However, there is increasing geographic diversification in the market. Through 2028, the top 10 countries' market share is projected to decline to approximately 72 percent.

1.2.1 Increasing Utility-Scale Market Share for Li-ion Batteries

Falling prices and flexible project designs have made Li-ion batteries the fastest growing energy storage technology. Annual new capacity additions are projected to ramp aggressively from 1,015 MW in 2019 to 15,682 MW in 2028, bringing total installed Li-ion battery capacity to a projected 80,908 MW and 69.5 percent of the estimated 116.5 GW global market by 2028. In terms of utility-scale capacity, Li-ion batteries are expected to account for 65 percent of new energy storage installations globally in 2019 and to exceed 17 GW by 2027.

Section 2

LI-ION BATTERY ENERGY STORAGE

2.1 Risks, Drawbacks, and Concerns

Concerns associated with the manufacture, use, and disposal of Li-ion batteries include safety, short lifespans, and lack of recycling capacity. These concerns also include global supply chain risks, potential price volatility, and significant environmental and social issues related to key raw materials. An examination of Li-ion battery energy storage should take these concerns into account and consider alternative energy storage technologies.

2.1.1 Safety

The primary safety concern with Li-ion batteries is the risk of fire due to thermal runaway, a situation in which the narrow range of safe operating temperatures is exceeded, initiating an unstoppable chain reaction. Li-ion batteries are designed to operate safely at temperatures between 15°C–45°C (59°F–113°F). At temperatures above 60°C (140°F), which can occur due to a short circuit or excessive current resulting from charging or discharging the battery too rapidly, the battery becomes unstable. Increased temperatures cause the release of additional energy, which raises temperatures even more. At temperatures above 100°C, the onset of thermal runaway becomes increasingly likely, and at temperatures above 144°C (291°F), it is almost inevitable.

Li-ion chemistries vary in terms of safety profiles, whereas more expensive and robust chemistries (like lithium iron phosphate and lithium titanate oxide) typically used in utility-scale applications are more stable than less expensive alternatives. Stability and thermal runaway remain significant concerns in the industry. Recent fires have impacted the stationary energy storage market and have prompted an increased focus on safety.

South Korea has led the world in battery energy storage capacity for 2 consecutive years and currently has nearly 25 percent of the world's Li-ion battery energy storage capacity. However, there were 23 reported fires in 2018, equating to tens of millions of dollars in losses. Of the approximately 1 GW of total installed capacity in South Korea, 40 MW (4 percent) of the installed capacity has been affected. As a result, 50 percent of South Korea's energy storage systems have been taken offline for inspection.

Many in the US attributed the South Korean Li-ion battery fires to poorly integrated systems. However, a 2019 fire at a Li-ion battery energy storage facility operated by Arizona Public Service (APS) has prompted a reevaluation of safety protocols for these systems in the US. Commissioner Sandra Kennedy issued a letter as part of the Arizona Corporation Commission's docket on the fire, in which she states that Li-ion batteries that use the types of chemistries involved in the APS fire "are not prudent and create unacceptable risks."[1]

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[1] Sandra D. Kennedy, "Arizona Corporation Commission Docket E-01345A-19-0076," (letter to the Commission, August 2, 2019), https://assets.documentcloud.org/documents/6240841/ACC-August-2-Kennedy-Letter-E000002248.pdf.

2.1.2 Short Lifespan

The exact cycle life of Li-ion batteries varies depending on the specific sub-chemistry used. Less expensive and less stable chemistries such as lithium cobalt oxide and lithium manganese oxide can have a relatively short cycle life in the range of 300–2,000 cycles, depending on manufacturer and usage. Alternatively, more robust chemistries such as lithium iron phosphate and lithium titanite oxide can last for 6,000–12,000 cycles. Depending on the specific services a system provides and the number of cycles per day, the calendar life for Li-ion batteries in grid storage applications may be as low as 3 years before capacity degradation occurs.

There are three approaches to addressing the relatively short cycle life of Li-ion batteries: replenishment of depleted materials, topping up the system by adding fresh modules to maintain the system's nameplate capacity, or fully replacing the system. While these methods can be effective in extending the life of a Li-ion battery project, they also result in expensive, recurring operations and maintenance costs.

*A system's **cycle life** refers to the number of times it can cycle or be charged and discharged before it degrades and becomes inoperable or unusable for a given application.*

Of the five commercial long duration energy storage technologies, four have cycle lives that greatly exceed Li-ion batteries (pumped hydro, compressed air, flow batteries, and molten salt batteries). In the context of applications for the electrical grid, longevity is desirable from the standpoint of both reliability and ratepayer costs, and utilities are accustomed to deploying infrastructure assets that will last for decades.

Table 2-1. Average Cycle Life and Expected Lifespan of Long Duration Energy Storage Technologies

Technology	Cycle Life	Expected Lifespan
Pumped Hydro Storage	Technically Unlimited	50–100 years
Compressed Air Energy Storage	Technically Unlimited	20–40+ years
Flow Batteries	10,000+ cycles	20–25+ years
Molten Salt Batteries	4,500–10,000	15–20 years
Lithium Ion Batteries	500–10,000 cycles	3–15 years

(Source: Navigant Research)

2.1.3 Supply Chain Risks and Sustainability Concerns

The dramatic rise in portable electronics coupled with expected growth in the use of EVs and grid-connected battery storage systems has put increasing pressure on supply chains for the raw materials needed to produce Li-ion batteries. Lithium, cobalt, nickel, and graphite are all critical, with little flexibility for material substitution. In addition, limitations on supply diversity for some of these elements introduces risks to both individual firms and national interests. This section reviews supply chain concerns for lithium and cobalt in closer detail and examines sustainability concerns for four critical materials.

2.1.3.1 Lithium Supply and Geopolitical Concerns

There is little concern regarding lithium shortages. Lithium is an abundant mineral available from several concentrated sources; however, the industry's ability to increase battery-grade production to meet projected future demand is less certain.

Lithium is sold and used in two key forms: lithium carbonate, mainly produced from brines, and lithium hydroxide, which is largely produced from mined hard rock sources. Lithium hydroxide is the preferred form, because it offers longer battery life and larger capacity, two key factors in battery quality.

Only eight countries produce lithium, and of these, three—Chile, Australia, and China—account for over 85 percent of global production. In addition, four companies—Albemarle Corporation, FMC Corporation, Sociedad Química y Minera (SQM), and Talison Lithium—command 61 percent of the world's lithium mine output. While the global supply of both forms of lithium is sufficient to meet demand, the potential supply constraints combined with uncertainty about the rate of EV adoption make it difficult to forecast future long-term pricing, which has fluctuated in recent years.

2.1.3.2 Chinese Control of Global Lithium Supplies

Chinese companies have acquired substantial stakes in lithium mines around the world to secure the lithium resources needed to drive expansion. In late 2018, China-based Tianqi Lithium spent more than $4 billion to purchase a 23.8 percent stake in SQM, one of the world's largest and lowest-cost producers of lithium. Tianqi also owns 51 percent of a large Australian lithium mine. Combined with the nearly 20 percent of global lithium reserves held in-country, China now controls 40 percent of world supply.

Given the increasing strategic importance of lithium, China's control of nearly half the world's supply has caused some concern. In April 2019, France and Germany asked the European Commission to support a $1.9 billion battery cell consortium to challenge China's growth in the space. With the US–China trade war intensifying, several Chinese state media outlets have also begun floating the idea of banning exports of rare-earth elements to the US as a possible response to President Donald Trump's decision to increase tariffs on Chinese goods. As a result, American lawmakers are beginning to investigate options to reduce the nation's dependence on China for lithium imports and processing.

2.1.3.3 Cobalt Supply and Geopolitical Concerns

Less than 10 percent of cobalt occurs as a primary product. The remaining 90 percent, known as mine supply, is produced as a byproduct of copper and nickel mining, linking its availability to the supply and demand dynamics of its parent materials. Experts estimate that around 68 percent of global production is concentrated in the Democratic Republic of Congo (DRC), a figure some sources estimate could rise to 73 percent by 2023.[2]

[2] Jason Deign, "Reliance on Congo Cobalt Grows Despite European Discoveries," *Greentech Media*, https://www.greentechmedia.com/articles/read/congo-cobalt-reliance-grows-despite-europe-discoveries#gs.to97yv, June 5, 2018.

2.1.3.3.2 *The "Blood Diamond of Batteries"*

This heavy dependence on the DRC has stark implications for sustainability given the well-documented human rights abuses of its mining industry, which have prompted some to call cobalt the "blood diamond of batteries." The DRC's copper belt accounts for almost half of the world's cobalt reserves at 3.75 million tons. While the majority is excavated at large-scale industrial mines, the DRC government reports that 20–30 percent of cobalt exports originate in artisanal mines, which are overwhelmingly unregulated and operate illegally. With an estimated 35,000 children employed in artisanal mines in the DRC, the ethical problem of child labor is a growing source of concern for all stakeholders. Poor working conditions in artisanal copper-cobalt mines also create serious health hazards for the estimated 255,000 laborers operating in the region. Over-exposure to cobalt can cause asthma, pneumonia, and heart and thyroid damage. The mines themselves tend to be little more than holes in the ground, with no suitable structural support to prevent collapse, and possess little or no protective equipment worn by the miners.

2.1.3.3.3 *Provenance and Traceability*

The issue of artisanal mining and child labor highlights one of the major challenges for cobalt consumers in the automotive, consumer electronics, and stationary storage sector, namely, the provenance and traceability of the material. Once mined, the mineral navigates a complex supply chain that can include the smelting of cobalt extracted from both artisanal and industrial mines, which is then exported overseas. China, which controls approximately 85 percent of global cobalt supply and produces some 60 percent of the world's refined cobalt, imports over 75 percent of its supply of the raw material from the DRC. The refined material is sold to battery manufacturers, which then sell their products to multinational brands. With no laws, widely acknowledged partnerships, or initiatives to support increased traceability for the metal, the lack of visibility down the supply chain leaves companies exposed to the ethical concerns tied to cobalt production. Systems that provide certainty about the origin of supplies and ensure they are not linked to child labor would likely result in a premium for certified materials, and also reduce the available supply for certain end-use sectors.

2.1.3.3.4 *Projected Price Volatility*

In addition to significant sustainability concerns, cobalt prices are expected to continue to increase due to production uncertainties. Cobalt refining is dominated by China, which accounts for approximately 60 percent of global production of refined cobalt. If midstream producers in other countries are to meet growing demand for cobalt from original equipment manufacturers, additional investment in refining capacity outside of China is needed. Given the projected increases in both EV adoption and the growth of portable electronics and stationary storage, cobalt demand is projected to increase fourfold between 2019 and 2028.

2.1.4 Environmental Impacts

Mining, processing, refining, and transporting four of the key materials required for Li-ion batteries—lithium, cobalt, nickel, and graphite—pose environmental risks. In addition, end-of-life concerns for spent Li-ion batteries are mounting as the use of Li-ion batteries for stationary energy storage expands.

2.1.4.1 Pollution

According to the US Environmental Protection Agency's recent life cycle analysis of Li-ion batteries, upstream materials extraction and processing and battery production pose significant potential for the eutrophication of bodies of water, ozone depletion, and ecological toxicity. For example, the production of soda used in processing lithium salts can lead to the creation of smog, which reduces visibility, causes eye and respiratory irritation, and harms vegetation. Aluminum production for the cooling system, cathodes, and other parts of the batteries is also highly energy intensive.

A 2016 *Washington Post* article on the impact of graphite mines and processing plants on China's air and water quality shed light on the global scale of environment degradation fueled by Li-ion battery production. China controls 70 percent of global graphite production capacity and experiences pollution from graphite mines and refineries that has resulted in stunted and damaged crops, high emissions of soot and particulate matter, and polluted water.

Similarly, nickel production is harsh on the environment. Processing the ore releases significant sulfur dioxide emissions, and like any ore mining activity, produces large amounts of slag. The Russian city of Norilsk is considered one of the most polluted places in the world, in large part because of nickel production. The Norlisk Nickel factory emits nearly 1.87 million tons of sulfur dioxide annually, and a river that runs through Norlisk famously turned bright red in 2016 after a flood washed mine waste into the river, a situation that was repeated in 2018.

The environmental impacts of China's extraction of mineral resources used in Li-ion batteries have also led to social unrest across Tibet. Since 2009, there have been more than 30 public protests against mining in response to the impact these activities have had on grasslands and rivers. In 2016, Ronda Lithium released toxic mine waste into a river in eastern Tibet, causing serious water pollution and the mass death of fish, resulting in local protests against the mining company. In 2013, lithium mine waste contaminated the same river, killing aquatic life and making local drinking water toxic.

2.1.4.2 GHG Footprint

As the use of Li-ion batteries for stationary storage becomes more prevalent, understanding the greenhouse gas (GHG) emissions burden of their production is increasingly important. A recent study conducted by the IVL Swedish Environmental Research Institute, on behalf of the Swedish Transport Administration and the Swedish Energy Agency, investigated the climate impact of Li-ion batteries from a life cycle perspective. The report concludes that for each kilowatt-hour of storage capacity in a Li-ion battery, emissions of 150 to 200 kg of CO_2 equivalent are generated.

Mining and refining were found to contribute to a relatively small portion (10–20 percent) of GHG emissions, independent of cell chemistry. The largest share (almost 50 percent) of GHG emissions result from battery manufacturing. This stems from the fact that the largest energy input in the production of Li-ion batteries is electricity. The IVL Swedish Environmental Research Institute study finds that energy efficiency and the electricity mix in the production stage present the best short-term opportunities to reduce the GHG emissions associated with Li-ion batteries.

These results were echoed by a recent study that estimated the GHG emissions from the production of Li-ion batteries in China and found that Li-ion batteries manufactured in China had GHG footprints that were double that of Li-ion batteries manufactured in the US due to the countries' respective electricity mixes.[3] Given that China is expected to control about two-thirds of global Li-ion battery manufacturing capacity by 2023, this elevated GHG emissions rate is significant.

2.1.4.3 *Water Impacts*

Water shortages and toxic spills from lithium mining in South America and Tibet further highlight the environmental concerns surrounding lithium extraction. One ton of lithium typically requires nearly 500,000 gallons of water to produce. As discussed in Section 2.1.3.1, lithium carbonate is produced from brines. Closed-basin brines, like those in South America's Lithium Triangle, are located primarily in arid regions where groundwater aquifers are rare and annual rainfall is limited. While the water pumped from the brines is undrinkable, the void left by these operations may be refilled by fresh groundwater. This can result in valuable water supplies in these locations being diverted away from local communities. In Chile's Salar de Atacama, for example, the lithium mining industry has used up to 65 percent of all available water in the region. Local communities in the region—many of them indigenous—are calling for the industry to be regulated.

2.1.4.4 *Decommissioning and Disposal*

As the market for stationary battery storage continues to grow, the question of how to deal with them at the end of their life cycle becomes more urgent. Li-ion batteries are classed as a dangerous good and are environmentally hazardous if disposed of incorrectly. The focus has primarily been on the disposal of hazardous materials used in Li-ion technology, rather on than extracting the materials for reuse. While cobalt has been historically recycled given its high value and use in alloys, recycling of Li-ion batteries is still in its infancy.

In the context of recycling automotive Li-ion batteries, a major factor that could temporarily delay the number of batteries sent for recycling is the potential to reuse them. It is anticipated that after primary usage in EVs, reuse in other applications such as stationary storage will become prominent. Repurposing EV batteries for use in stationary energy storage applications is already under commercialization and is viewed as a viable option. However, the lifespan of these reused Li-ion batteries will be even shorter than that of batteries purpose-built for grid usage, and this reuse delays fully dealing with the material recycling issues.

[3] Hao Han, Mu Zhexuan, Jiang Shuhua, Liu Zongwei, et al, *GHG Emissions from the Production of Lithium-Ion Batteries for Electric Vehicles in China*, MDPI, http://www.mdpi.com/2071-1050/9/4/504/pdf, April 4, 2017.

Section 3

CONCLUSION

3.1 An "All of the Above" Approach

Energy storage is critical to the successful integration of large amounts of renewable energy and will play a major role in the decarbonization of the electricity grid. As the use of Li-ion batteries for renewable energy storage increases, it is important to recognize that while they are a suitable technology for certain applications, there are a wide range of concerns surrounding their manufacture, use, and disposal.

These concerns include safety, short lifespans, and lack of recycling capacity, as well as global supply chain risks, potential price volatility, and significant environmental and social issues related to key raw materials. Utility planners, regulators, and policymakers who seek to objectively evaluate the benefits and risks of Li-ion battery energy storage should take these concerns into account and give full consideration to alternative long duration energy storage technology options.

Pumped hydro storage is a well-established renewable energy storage technology that offers longevity, cost-effectiveness, energy security, and local economic development benefits. In addition, pumped hydro storage facilities have limited impact on the environment and decommissioning at the end of their 50- or 100-year lives is relatively straightforward.

Ultimately, the integration of large amounts of intermittent renewable energy sources will necessitate an "all of the above" approach to energy storage. Informed public policy and utility resource planning can help ensure that ratepayers receive the best value for their collective investment in energy storage infrastructure.

Section 4

ACRONYM AND ABBREVIATION LIST

DRC	Democratic Republic of Congo
EV	Electric Vehicle
GHG	Greenhouse Gas
kWh	Kilowatt-hour
Li-ion	Lithium Ion
MW	Megawatt
MWh	Megawatt-hour
SQM	Sociedad Química y Minera
US	United States

Section 5

SCOPE OF STUDY

This white paper examines the market for long duration energy storage technologies on the power grid. Specific attention is paid to the risks associated with battery energy storage, including environmental impact and supply chain concerns. Navigant Research prepared this white paper to provide an independent analysis of the opportunities for long duration energy storage. This white paper does not consist of any endorsement of any specific technology, project, or company. Rather this paper provides readers with an understanding of the market for long duration storage and why it will be required for a future grid reliant on renewable energy generation.

Published 3Q 2019

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