Reconsidering Planned Generation

Future-proofing electricity affordability, reliability, and security in a rapidly changing world

Report / June 2026

Authors and Acknowledgments

Authors

Selena Kay Galeos
Rachit Kansal
James Sherwood

Contributors

Janela Cantre, Diego Angel Hakim, Sidney Jules, David Lone, Tyeler Matsuo, Matt Miccioli, Obianuju Ugwu-Oju, and Paula Valencia.

Authors and contributors listed alphabetically.
All authors and contributors are from RMI unless otherwise noted.

Contacts

Rachit Kansal, rkansal@rmi.org
James Sherwood, jsherwood@rmi.org

Copyrights and Citation

Selena Kay Galeos, Rachit Kansal, and James Sherwood, *Reconsidering Planned Generation*, RMI, 2026, http://rmi.org/resources/reconsidering-planned-generation-report.

Acknowledgments

The authors would like to thank the following individuals for their contributions to this work as reviewers: Andrew Allee, RMI; Lumen Balboa, Alsons Power Group; Koben Calhoun, ReEnergi Solutions; Sonika Choudhary, RMI; Joseph Curtin, The Rockefeller Foundation; Mark Dyson, RMI; David Elzinga, Asian Development Bank; Tim Guanzon, Client Earth; Phillip Hannam, World Bank Group; Alex Hurley, Global Energy Monitor; Paul Jacobson, Clean Energy Bridge; Natalie Janzow, The Rockefeller Foundation; Ayato Kurokawa, Asian Development Bank; Yujing Li, RMI; Genevieve Lillis, RMI; George Mowles-Van Der Gaag, The Carbon Trust; Juan Quiroga, The Carbon Trust; Christine Shearer, Global Energy Monitor; Vikram Singh, RMI; Julia Skorupska, Powering Past Clean Alliance; and Pradeep Tharakan, Asian Development Bank.

This insight brief was produced with support from The Rockefeller Foundation. The findings and conclusions contained within are those of the authors and do not necessarily reflect positions or policies of The Rockefeller Foundation.

Table of Contents

About RMI

Rocky Mountain Institute (RMI) is an independent, nonpartisan nonprofit founded in 1982 that transforms global energy systems through market-driven solutions to secure a prosperous, resilient, clean energy future for all. In collaboration with businesses, policymakers, funders, communities, and other partners, RMI drives investment to scale clean energy solutions, reduce energy waste, and boost access to affordable clean energy in ways that enhance security, strengthen the economy, and improve people's livelihoods. RMI is active in over 50 countries.

Introduction

Power sector decision makers have an increasingly difficult job balancing competing priorities and crises — yet this moment simultaneously offers new opportunities driven by innovation in clean technologies. Power sector leaders around the world are operating at a particularly difficult moment in history. Demand is growing rapidly, extreme weather events are increasing in frequency and severity, and geopolitical disruptions are ongoing.[i] These create enormous uncertainty and challenges for power sector planners who seek to provide people with reliable, affordable, and secure electricity that strengthens the economic competitiveness of their countries.

But this is also a time of tremendous opportunity. The past decade has seen unprecedented technological advancement, much of it in clean energy — solar and wind costs have respectively fallen by **70% and 55%** and are now the cheapest sources of energy on much of the planet; battery costs for firming those variable resources have **fallen by 90%**; and virtual power plants (VPPs) **grew by 33%** in North America from 2024 to 2025.

And more technologies are on the horizon, as long-duration energy storage (LDES), next-generation geothermal, and even small modular nuclear reactors navigate a path toward commercial viability. Paired with new planning approaches that help identify least-regrets investments under uncertainty, these resources can be deployed modularly to closely track demand growth and mitigate the risk of overbuilding or underbuilding.[ii] They can also provide speed to power, completing construction more rapidly than conventional resources. Although transitioning to these resources is neither simple nor linear, approaches to do so are improving just as quickly as costs are declining.

Low- and middle-income countries (LMICs) — particularly those reliant on fuel imports for electricity generation — face significant questions amid these trends given plans for grid-connected coal expansion. Nowhere is the confluence of these trends more acute than in LMICs, where electricity system change has been particularly dynamic, and which are **projected to drive most future electricity demand** globally through 2035.[iii] Many LMICs also import a significant portion of their coal and/or natural gas fuel supply for **energy** and **electricity** use, subjecting their sectors to volatile prices.[iv] This creates an urgency for countries to reevaluate power sector planning in tandem with addressing enabling conditions to unlock adoption of alternative sources of low-cost electricity.[v]

In the immediate term, there are many planned generation investments that might be important to reconsider, given both ongoing trends and acute price shocks that are upending traditional approaches

---

[i] In 2024, electricity demand grew by **4.3%,** markedly higher than the **2.5% average growth rate of the 2010s**. Although driven in part by extreme weather, the International Energy Agency (IEA) forecasts an annual growth rate of **close to 4%** from 2025 to 2027. IEA projects the rate of electricity demand growth will outpace the growth in overall energy use, with electricity's share rising from **21% today to 27% by 2035**.

[ii] Details on these approaches are included in RMI's 2026 report *Power System Planning in an Uncertain World* (forthcoming).

[iii] When referencing LMICs, RMI is referring to the **latest World Bank taxonomy** categorizing countries as low-income, lower-middle-income, and upper-middle-income economies.

[iv] Coal fuel prices have generally been less volatile than natural gas prices but do still experience price shocks, especially in the past decade (e.g., in 2022 **after Russia invaded Ukraine**, in **2026 with the closure of the Strait of Hormuz**).

[v] Enabling conditions vary by (and within) countries, but constraints may include access to and cost of finance, institutional capacity, data availability, grid limitations, legacy planning, and procurement practices.

to power system planning and operation. Planned, grid-connected coal plants represent one set of these.[vi] Historically, coal-fired generation has played a critical role in many LMICs — affordably electrifying economies, heating homes, enabling industrial development, and providing stable jobs. However, as the needs of the grid are changing, and as new technological capabilities are available, the use of coal for power generation in many countries has been in structural decline due to economic and operational pressures from alternatives (including gas), air pollution and environmental priorities, and shifts in needed performance characteristics.[vii] Meanwhile, recurring energy crises around the world raise questions about the security implications of relying on an imported supply of fuels priced on a global market.

Today, 640 gigawatts (GW) of grid-connected coal power remain in the development pipeline globally, with 630 GW of that planned in LMICs.[viii] These new plants may operate into the 2060s, or longer, given the average lifetimes of existing coal plants. If system operational and economic needs evolve, these plants may be underutilized and ultimately become burdens that increase costs to the system and to customers. Given the scale of disruption and pace of innovation, there is a critical opportunity to reconsider locking in these planned plants, and to test whether alternatives might better meet nations' goals of power sector affordability, reliability, energy security, and economic competitiveness.

For decision makers wrestling with these questions, this brief offers tools for determining whether planned coal plants are good candidates to be paused or reconsidered. There is no simple answer to the question of whether planned coal plants are or are not the best option for a power system. And some planned coal plants may remain the best option available for their particular situations, such as, in many combined heat and power (CHP) applications or areas with limited renewable resources availability. But recent work by RMI and partners directly with developers and power sector decision makers provides growing evidence that alternatives can better provide affordable, reliable, and secure power in many situations — all while remaining financially attractive to investors and project developers and creating benefits for local communities.

To support developers, regulators, government agencies, utilities, and stakeholders in evaluating whether planned grid-connected coal plants are good candidates for reconsideration, this brief provides:

- An overview of where and why coal power continues to be developed today;
- A simple framework to help decision makers identify planned plants that might be reconsidered;
- Suggested steps for applying the framework to evaluate candidate plants; and
- An appendix with details on how to assess the indicators relevant for planned plants and their economic competitiveness.

[vi] This brief focuses on grid-connected coal plants, recognizing that captive plants have a unique calculus, even while many of the trends and considerations presented here remain relevant.

[vii] Per **Global Energy Monitor (GEM)'s October 2025 data**, from 2014 to 2024, high-income country (HIC) net coal capacity decreased by 17 GW per year. **Per the IEA**, global coal demand growth slowed to 1.2% in 2024, with advanced economies' coal demand halving from its peak in 2007. In India and China, coal fleets are operating at average capacity factors of **66%** and **48%** in 2025, respectively, with China's having fallen from 60% in 2011.

[viii] See GEM's **Global Coal Plant Tracker**, October 2025 release.

Resources are available to support deeper analysis, and future briefs will share evaluations of specific plants and alternative options. Based on RMI's experience supporting developers and regulators in reevaluating plants, a significant number of planned grid-connected coal plants in LMICs could be ripe for reconsideration. For example, close to 30% of planned plants (or 170 GW) were first conceptualized a decade or more ago when capital and fuel costs, technologies, interest rates, and geopolitics looked quite different. And close to half of those plants remain in early stages of development, when most costs have not been locked in. As a first step, we encourage readers to apply the framework provided here against planned coal projects in their jurisdiction to begin identifying those that might be candidates for reconsideration.

In future briefs, we will explore the project-specific technical, economic, and financial viability of alternatives, and the situations where these alternatives are most likely to be attractive to all parties. Support is available from RMI and partners for stakeholders interested in more detailed study of specific power systems or plants — please contact **plannedpower@rmi.org**.

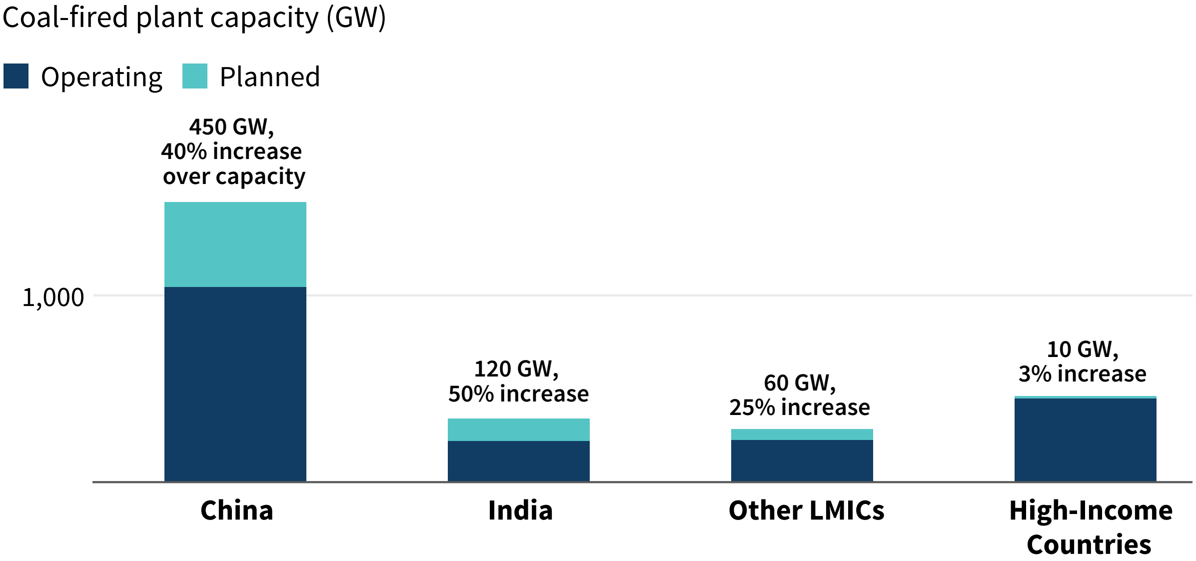
Current Context in Planned Coal Development

A significant amount of new coal capacity is planned globally, primarily in LMICs. The global landscape of coal-fired power has been transforming over the past decade — hundreds of gigawatts of coal plants under development have been canceled, with incremental coal plant additions in 2024 hitting their lowest level in two decades. There has also been significant momentum to transition operating coal plants ahead of schedule, especially where such plants have become uneconomic and are increasing electricity costs for customers. These forces have led to transition strategies and pilot projects being explored by governments, plant owners, and multilateral financial institutions.[ix]

Despite these shifts, according to Global Energy Monitor (GEM), as of October 2025 more than 640 GW of grid-connected coal plants are still under development globally.[x] As Exhibit 1 illustrates, if built, this would represent a 33% increase in the world's grid-connected coal-fired capacity. This data is directionally accurate but imprecise, both because planned projects do not always reach completion, and because not all planned projects have been publicly announced (e.g., they may exist in the business plans of plant owners, or as notional capacity in utility resource plans).

Exhibit 1

Breakdown of planned and operating global coal capacity, by country



RMI Graphic. Source: GEM, *Global Coal Plant Tracker*, October 2025 release

---

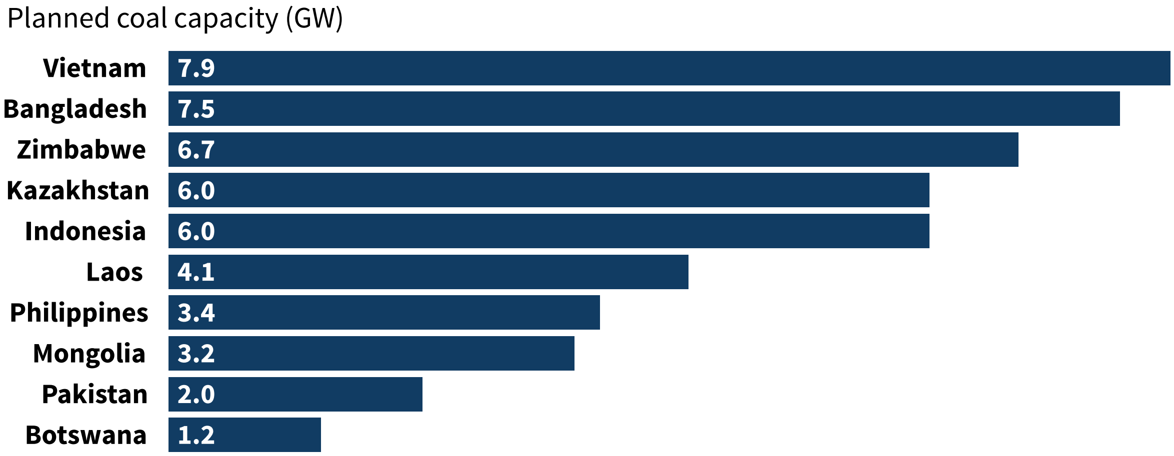
ix In the past decade, similar forces have driven the wave of (primarily LMIC) coal plant cancellations, the limited build-out of coal in HICs, and some existing coal plants becoming uneconomic. This includes economics (declining clean energy, BESS, and natural gas–fired power plant costs) and policies (air pollution regulation, emissions trading schemes, legally binding coal transition targets). In HICs, this was strengthened by slower electricity demand growth for an extended period and stronger financial markets.

x An additional 50 GW of coal capacity is planned for providing electricity and/or heat directly to specific industrial and commercial customers, rather than to the broader grid. These plants have significantly different development circumstances and economics and are not the focus of this brief.

This planned, grid-connected coal capacity is spread across more than 1,000 units, 31 countries, and five continents. Over 98% of this capacity (630 GW) is being planned in LMICs, with just under 11 GW of planned grid-connected capacity in high-income countries (HICs). As Exhibit 1 shows, India and China dominate build-out, but a range of other LMICs are also planning coal-fired power plants — the 10 countries with the most capacity (Exhibit 2) have approximately 50 GW in planned, grid-connected capacity.

Exhibit 2

Top 10 LMICs (excluding India and China) with the most planned grid-connected coal capacity



RMI Graphic. Source: GEM, *Global Coal Plant Tracker,* October 2025 release

The pipeline of planned capacity includes many plants that were conceived long ago and have been revived in moments of crisis. GEM has tracked data on planned coal plants around the world since 2014, including how plants have moved between development stages. As Exhibit 3 shows, a surge in coal plant initiation occurred between 2022 and 2025.[xi] This surge was driven in part by price shocks in the global liquified natural gas (LNG) market following the invasion of Ukraine by Russia and resurgent electricity demand coming out of COVID. In China, rapidly growing demand for power, a 20-year record-low river flow and hydropower, lack of power system flexibility, and increasing concerns about energy security led to an acceleration of new coal power approvals in 2022–23.

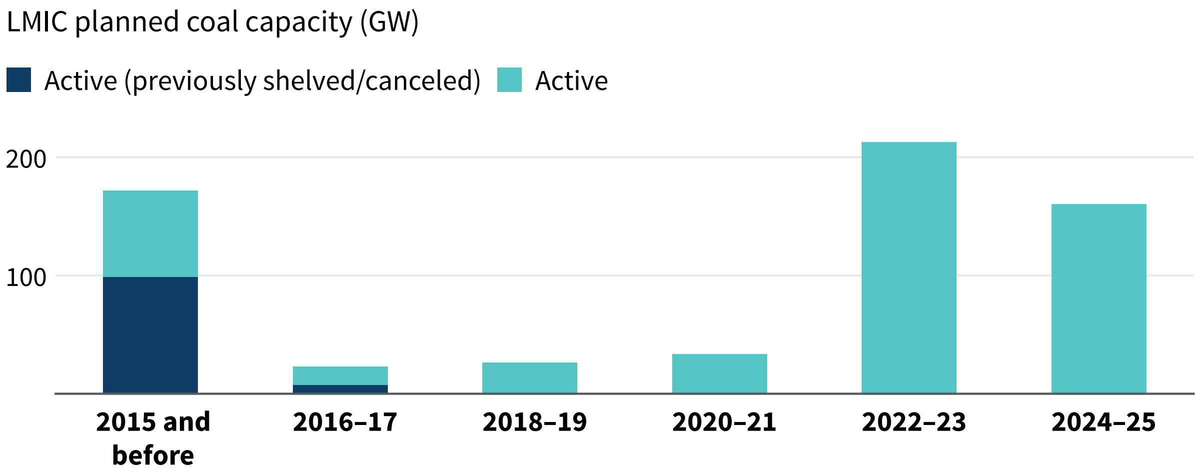
Notably, 28% (over 170 GW) of coal capacity planned in LMICs today was conceived prior to 2016 — more than a decade ago — with an additional 50 GW initiated between 2016 and 2020. Most of these plants (100 GW) were at one point shelved or canceled before being brought back into active development.[xii] As Exhibit 4 shows, there was a spike in reviving these plants during the same period as the increase in new project starts (2022–25) as countries sought rapid, off-the-shelf solutions amid those crises.

[xi] GEM has tracked year-to-year changes from 2014 to 2025. RMI defined the year of a coal plant's initiation as the year it first appears in the GEM database (assuming the plant is still under development today), even if it was shelved or canceled in intervening years.

[xii] GEM defines projects as shelved when they have not shown signs of advancement for two to four years, and considers projects canceled when they have been either inactive for over four years or have been officially terminated by a project sponsor or the government.

Exhibit 3

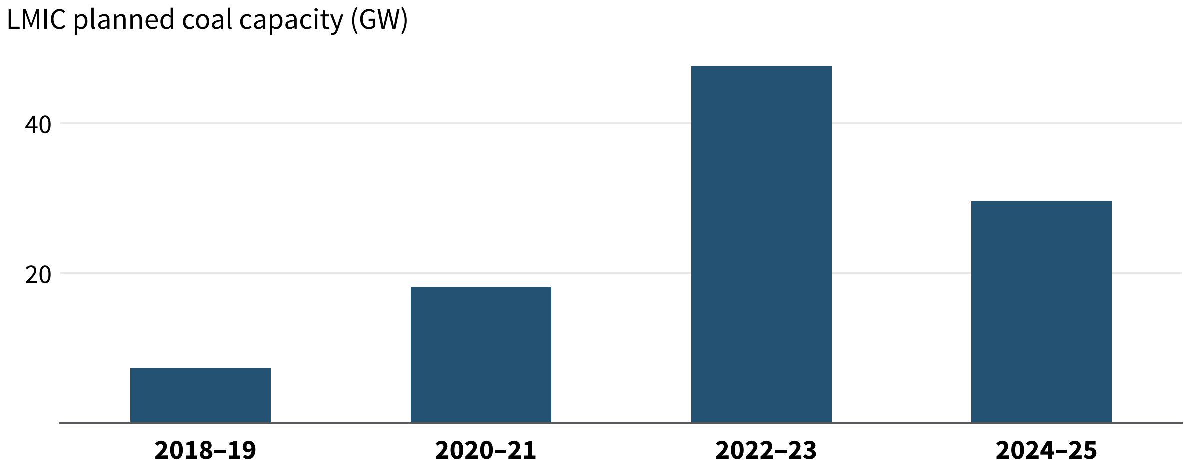
Initiation year for coal plants in the LMIC development pipeline



RMI Graphic. Source: GEM, *Global Coal Plant Tracker*, October 2025 release

Exhibit 4

Years when initially canceled or shelved LMIC coal plants were brought back into planning



RMI Graphic. Source: GEM, *Global Coal Plant Tracker*, October 2025 release

There are logical reasons that grid-connected coal plants were originally selected in many situations. Both individual power plants and system planning processes are unique across countries planning to add new coal capacity. But most share a similar set of factors that have led to selecting these plants in their power development planning, including:

- **Cost competitiveness** — Depending on available resources, land constraints, load and grid dynamics, and local energy supply chains, new coal power may be considered an economically competitive supply option to deliver reliable electricity. Historically, favorable **financing** costs and terms for coal plants have also contributed to this selection.

- **District and industrial heat requirements** —Planners needing to serve industries requiring process heat and/or district heating may significantly constrain available technology options. Although this brief focuses on planned coal plants providing electricity, innovative solutions are increasingly available for heat-oriented applications.[xiii] Of the 640 GW of grid-connected coal power planned in LMICs, around 110 GW is slated to provide a CHP function.

- **Perceived energy security** — Among nations that import fossil fuels for electricity generation, coal is often considered to be more reliably available and affordable relative to other resources. The LNG price shocks noted earlier contribute to this perception, while the continued geopolitical dynamics including from the Persian Gulf conflict and delays both **in gas turbine delivery** and in **gas infrastructure and LNG terminal build-out** may contribute to the selection of coal by planners.

- **Legacy operational practices and assessments of grid needs** — Power system plans are inherently dependent on an understanding of current and future load, and what the grid needs to provide as a result. Legacy assessments of grid needs may have pointed toward a continued need for “baseload” generation, which may particularly be a driver behind the 35% of the planned coal pipeline that was initiated prior to 2020.[xiv] However, these grid needs are rapidly evolving and, in many geographies, there is an increasing need for flexibility and peaking capacity. Grid operators may also be more comfortable with an overabundance of conventional resources as they become more familiar with strategies to integrate increasing variable and inverter-based resources.

- **Legacy planning assumptions and procurement practices** — Technology availability, capabilities, and costs are changing just as rapidly as grid needs. Planning models that include outdated and inaccurate estimates of these parameters, or omit technologies entirely, can lead to prioritization of conventional resources that are no longer economically optimal. For example, battery energy storage system (BESS) costs have declined much faster than many forecasts anticipated, leading to power development plans that did not consider scenarios representative of today’s reality. Similarly, if procurement practices have not been updated to be inclusive of newer technologies, they may give preference to coal and other thermal generation.[xv]

Recognizing these factors, the following section provides a framework for considering whether they hold true for individual planned plants, and what the implications might be on whether to reconsider them relative to alternative options.

[xiii] For example, by **replacing** or **augmenting** district heating systems with small-scale electric heat pumps for indivudual users, integrating **large-scale** heat pumps into existing networks, and through the use of next-generation **geothermal technologies to provide heat** in regions with previously uneconomic resources.

[xiv] Baseload power is considered near-continuous operation of a power plant to provide bulk energy supply.

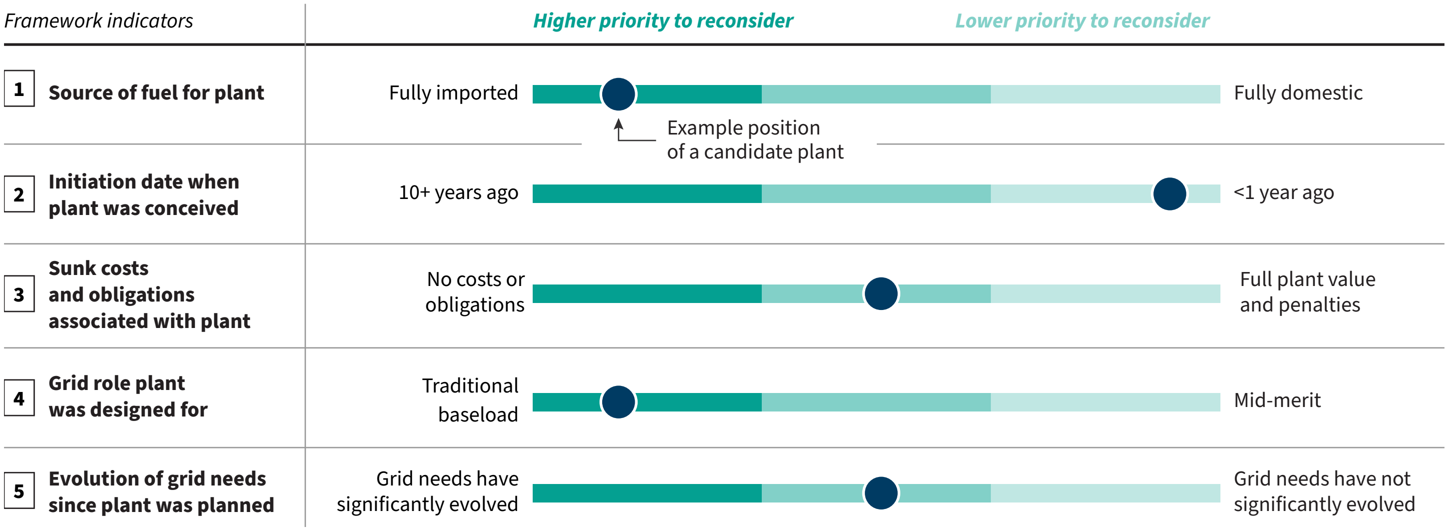
[xv] For more information on evolving best practices around planning, see RMI’s reports on *Reimagining Resource Planning* (2023) and *Power System Planning for an Uncertain World* (forthcoming, 2026).

A Framework for Identifying Planned Plants to Reconsider

Power sector decision makers and developers can identify plants to reconsider by assessing how they map to key indicators. Taking the global context into consideration, a power sector planner or a developer with planned coal can quickly evaluate whether a plant should be reconsidered to ensure affordable, reliable, secure electricity supply. Considering grid-connected plants intended for electricity supply, Exhibit 5 provides a simple framework for decision makers to evaluate whether a given plant is a good candidate to reconsider alongside alternatives. As described in the following section, this can serve as a first step that can be conducted quickly and can help determine whether a more detailed feasibility study is warranted.[xvi]

Exhibit 5

Simplified framework with five indicators to identify planned grid-connected coal plants that are candidates to reconsider



Note: Plants with indicators toward the left end of the spectrum are *higher priority to reconsider*; plants with indicators toward the right end of the spectrum are more likely to be *lower priority to reconsider.*

RMI Graphic. Source: RMI analysis

[xvi] This framework is meant as a directional decision-making tool and is focused on techno-economic and financial considerations for individual plants. Political and social factors (e.g., priorities around domestic coal resources, impacts, and opportunities for communities) are also important to consider when reassessing plants. Although this brief frames the process around an individual plant, similar analyses can be conducted at a regional or system level (e.g., for a grid where multiple new coal plants are planned).

This framework revolves around five key indicators to help decision makers determine whether to further assess the economic competitiveness of alternatives to a planned coal plant, in the context of evolving grid needs:

- **Indicator 1: What is the source of fuel for the coal plant?** The plant's fuel source has implications for both energy security and affordability. Imported fuels will be exposed to greater risk of supply disruption relative to domestic production, while also exposing customers, offtakers, taxpayers, or the developer to commodity price volatility and foreign exchange risk, which may not always be mitigated by fuel supply agreements (FSAs).

- **Indicator 2: When was the plant originally conceived?** Plants that have been under development for an extended period are more likely to be uncompetitive compared with alternatives. These plants were selected and designed at a time when technology, financing, and fuel cost projections were significantly different, and grid needs may have significantly shifted since then.

- **Indicator 3: What sunk costs and contractual obligations are attached to the plant?** As a project progresses through development stages, it accrues sunk costs and obligations. These include invested capital (such as for acquired land and plant equipment) as well as contractual obligations and fees or penalties to exit those contracts (including power purchase agreements [PPAs], FSAs, and engineering, procurement, and construction [EPC] contracts). The greater these sunk costs and obligations, the more expensive a transition to an alternative will be. For most of the development time frame, these costs and obligations are minimal and increase quickly as financial close is reached and construction begins. If plant owners forgo future revenues by transitioning to an alternative, additional compensation may be required. Although financial instruments may be available to offset these various costs, plants in earlier development stages generally have fewer costs and are more straightforward candidates to reconsider.[xvii]

- **Indicator 4: What role was the coal plant originally designed to play on the grid?** Although conventional definitions of baseload and mid-merit resources are becoming less useful in the context of rapidly evolving grid needs, these constructs are still the basis around which most planned coal plants have been designed. Mid-merit resources typically follow predictable dispatch patterns with moderate ramping flexibility, while baseload resources are expected to operate effectively continuously, with minimal cycling. Historically, it has been much more common for coal plants to be designed as baseload resources, but advanced combustion technologies and design modifications can enable coal plants to play a more flexible role on the grid, closer to a mid-merit resource.[xviii]

  However, even the most advanced coal plants are not as flexible as combined-cycle gas turbines commonly built to provide mid-merit capacity, and far less flexible than BESS resources. In addition to technical capabilities, contractual constraints also inform the role a coal plant is likely to play on the grid. For example, plants designed and contracted on the expectation of a need for baseload energy are more likely to become uncompetitive (or even liabilities) as grids modernize and are strong candidates to reconsider.

[xvii] For example, these additional costs could be offset through concessional financing from multilateral development banks, blended finance platforms, or patient capital.

[xviii] Ultra-supercritical coal plants, for example, have higher ramp rates than subcritical coal plants. This enables them to play a mid-merit role more effectively. Even the most flexible coal plants remain, at best, similar to older or less flexible combined-cycle natural gas plants, while significantly less flexible than open cycle combustion gas plants or battery energy storage in terms of startup time, ramp rate, and minimum loading.

- **Indicator 5: How have grid needs evolved since the coal plant was planned?** A range of factors may have driven an evolution of grid needs since the coal plant was first planned. This evolution could include increased variable renewable energy deployment and changes in the system's net load profile, shifts in resource adequacy needs and procurement strategies, or differences in what grid services are undersupplied (among many other factors). The potential addition of new large loads including data centers, industrial hubs, and electrification may be an important consideration as well. If this evolution has already occurred or is anticipated in the near future and these dynamics were not factored into the plant's selection and design, it is a good indicator that the plant should be reconsidered. Ideal least-regrets resource plans will be future-proofed to allow for modularity and both operational and procurement flexibility to meet these evolving and uncertain grid needs.

Although they contain layers of complexity, these indicators can generally be evaluated quickly by decision makers with knowledge of a country's power sector. **To apply the framework to a plant, a decision maker need only identify the approximate position on each indicator's sliding scale**, as discussed in the following section. Depending on how a plant measures up, it might fall into one of the following categories:

- **Higher priority to reconsider:** These plants will have most of their indicators toward the left side of the spectrum on the framework. For example, for a plant with limited sunk costs that was planned as baseload in a grid where the needs have evolved significantly, alternatives are likely to be technically preferable and economically competitive.

- **Higher priority to reconsider with additional financial or technical support:** These plants might have only one or two indicators toward the left side of the spectrum. For example, a plant designed for baseload where the grid's needs have evolved, but which was recently planned, will use domestically sourced fuel, and has meaningful sunk costs. Alternatives might be more competitive than this plant, but only if financial support is available to overcome sunk costs.[xix]

- **Lower priority to reconsider:** Plants in this category might be more competitive options based on high-level economics and grid needs. For example, these might be recently planned plants with significant sunk costs, designed to play a role that is aligned with what the grid needs both today and into the future, and using domestically sourced fuel that is cost competitive and reduces energy security risk. These plants may be lower priority relative to other assets for plant-specific study, but may still be reconsidered as part of a broader reevaluation at the system level.

[xix] This could also include situations where technical support is needed to better understand evolving grid needs or to support regulatory adjustments to utilize alternative technologies, for example.

Applying the Framework to Reevaluate Planned Plants

Reevaluating a plant — or plants — can be approached in three phases, as shown in Exhibit 6. Exploration of a plant during these phases can of course be stopped at any time, but these offer natural points where sufficient new information is available to decide how to proceed. This brief focuses on Phase 1, while future briefs will provide detail on other phases. Within Phase 1, there are two main steps: (1) placement on the framework, and (2) high-level analysis of economic competitiveness.

Phase 1, Step 1: Preliminary reconsideration of planned plant using framework

As noted in the previous section, a first step is to move through the five indicators and answer the top-line question to place the plant on the spectrum. The objective of this exercise is to determine whether there is a compelling reason to further evaluate a plant. Decision makers and stakeholders with deeper knowledge of both a country's power sector and the plant's history will likely be able to evaluate each indicator quickly. For more complex situations, Appendix A includes detailed considerations that may be helpful in evaluating each indicator and Appendix B applies the framework to illustrative plants.

The following guiding questions and hypothetical situations provide a starting point for applying the framework:

- **Indicators 1 and 2: Source of fuel and initiation date.** These indicators are straightforward to evaluate, and data is publicly available on each for nearly all planned plants globally, for example through GEM's **Global Coal Plant Tracker**. As noted above, this may introduce additional economic and social considerations to account for.

- **Indicator 3: Sunk costs and obligations associated with plant.** In comparison with either plant value at the beginning of commercial operation or costs incurred to complete coal plant, what degree of development costs has this plant incurred and/or what contractual obligations is it under? How significant are the penalties for exiting those contracts?

    - **Higher priority to reconsider:** A preconstruction plant that has minimal capital invested and has not yet signed EPC or FSA contracts (or where those can be exited or modified with limited penalty).[xx]

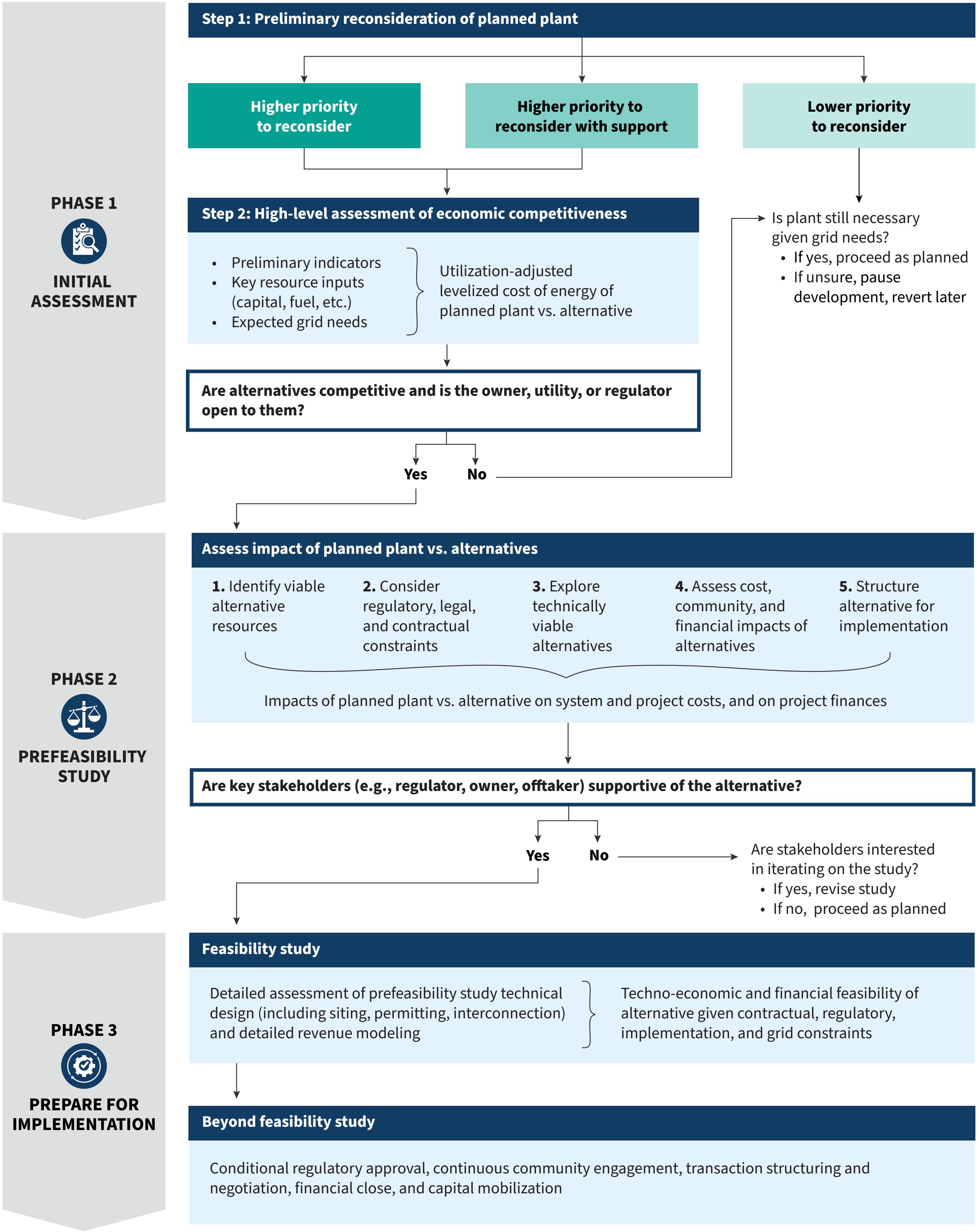
    - **Higher priority to reconsider with support:** A preconstruction plant that has a signed PPA contract and has reached financial close, and thus would incur exit penalties.

    - **Lower priority to reconsider:** An under-construction plant that is close to completion, with significant spent development costs and an FSA with stiff cancellation penalties.

[xx] Contract modification may be relevant in the case of, for example, an EPC that might still be utilized for development of an alternative generation project if the planned coal plant was transitioned.

Exhibit 6

High-level process to assess and advance alternatives to planned coal plants



PHASE 1

INITIAL ASSESSMENT

Step 1: Preliminary reconsideration of planned plant

Higher priority to reconsider

Higher priority to reconsider with support

Lower priority to reconsider

Is plant still necessary given grid needs?
- If yes, proceed as planned
- If unsure, pause development, revert later

Step 2: High-level assessment of economic competitiveness

- Preliminary indicators
- Key resource inputs (capital, fuel, etc.)
- Expected grid needs

Utilization-adjusted levelized cost of energy of planned plant vs. alternative

Are alternatives competitive and is the owner, utility, or regulator open to them?

Yes **No**

PHASE 2

PREFEASIBILITY STUDY

Assess impact of planned plant vs. alternatives

1. Identify viable alternative resources

2. Consider regulatory, legal, and contractual constraints

3. Explore technically viable alternatives

4. Assess cost, community, and financial impacts of alternatives

5. Structure alternative for implementation

Impacts of planned plant vs. alternative on system and project costs, and on project finances

Are key stakeholders (e.g., regulator, owner, offtaker) supportive of the alternative?

Yes **No**

Are stakeholders interested in iterating on the study?
- If yes, revise study
- If no, proceed as planned

PHASE 3

PREPARE FOR IMPLEMENTATION

Feasibility study

Detailed assessment of prefeasibility study technical design (including siting, permitting, interconnection) and detailed revenue modeling

Techno-economic and financial feasibility of alternative given contractual, regulatory, implementation, and grid constraints

Beyond feasibility study

Conditional regulatory approval, continuous community engagement, transaction structuring and negotiation, financial close, and capital mobilization

RMI Graphic. Source: RMI analysis

- **Indicator 4: Grid role plant was designed for.** What was the expected capacity factor for the plant when it was designed and financed? If the plant has not yet been fully designed, was it procured in alignment with robust and well-calibrated system planning? How flexible is the plant's compensation structure, and how much operational flexibility will its design allow?
    - **Higher priority to reconsider:** A subcritical coal plant with limited flexibility, designed for baseload, while the grid now requires flexible operation.
    - **Higher priority to reconsider with support:** A supercritical coal plant designed for baseload, sited in a grid needing flexibility, but its PPA disincentivizes flexible operation.
    - **Lower priority to reconsider:** An ultra-supercritical coal plant designed for baseload operation, which the grid still needs.
- **Indicator 5: Evolution of grid needs since plant was planned.** How and to what extent has the system's current and projected net load profile evolved since the coal plant's planning was initiated? How much variable renewable energy capacity is expected to be integrated during the plant's lifetime?[xxi]
    - **Higher priority to reconsider:** The grid has seen significant solar deployment since plant was planned, with capacity increasingly needed during evening hours.
    - **Higher priority to reconsider with support:** The grid has seen significant variable renewable deployment to the point that midday net load is minimal, meaning that additional renewable generation may require greater BESS pairing to shift power to evening hours.
    - **Lower priority to reconsider:** The grid the plant is to be sited in has limited existing baseload resources and limited variable renewable generation, such that net load is relatively flat and aligns well with the coal plant's operational characteristics.

Phase 1, Step 2: High-level assessment of economic competitiveness

If users of the decision framework in Step 1 conclude a planned coal plant is a candidate to consider (with or without technical and financial support), the next step is a high-level assessment of the coal plant's economic competitiveness compared with alternatives. Although definitively answering this question requires complex analysis (i.e., Phases 2 and 3 in Exhibit 6), a simple levelized cost of energy (LCOE) assessment is typically sufficient to inform a decision to proceed with more detailed study.

For the planned coal plant, LCOE can be informed by the five indicators above, and estimated from a short list of factors related to the project's design and location, such as capital costs, fuel costs, combustion technology, and utilization rate.[xxii] Critically, it is important to consider the plant's expected utilization rate in light of actual grid needs rather than the assumption made when the plant was planned or its expected

---

[xxi] For example, the IEA's reports *Integrating Solar and Wind* (p. 29) and *Integrating Solar and Wind in Southeast Asia* (p. 33) illustrate relatively conservative projections of future variable renewable capacity at a national level through 2035, based in part on national power development plans.

[xxii] For a full list of factors contributing to LCOE, see National Laboratory of the Rockies (NLR)'s **Annual Technology Baseline** methodology.

PPA price. For example, a plant that was planned to provide baseload power might have originally assumed a capacity factor of 75%. However, if grid needs have evolved, it may only be needed at a 50% capacity factor under updated assumptions. This would increase the plant's LCOE by roughly 30% (depending on the ratio of fixed to variable costs).

Alternatives to compare against should be selected based on an estimation of which technologies, or combination of technologies, may be able to meet the grid's needs as well as or better than coal. If that alternative includes variable renewable energy generation, calculating its LCOE would be a similar process to coal but also accounting for local resource availability (this affects the combination of renewable resources required to meet grid needs). For example, an alternative utilizing solar power as its primary energy source would require significantly more storage capacity to provide the equivalent of a coal plant operating at 75% compared with 50% capacity factor.[xxiii] RMI's analysis of electricity markets around the world, particularly those with limited domestic natural gas resources, has generally found that the most competitive options against planned coal include some combination of variable renewable energy paired with BESS.[xxiv]

To provide an example for how this comparison might look, Exhibit 7 compares the LCOE across a range of scenarios for a new ultra-supercritical coal plant against an alternative that includes solar generation paired with either four-hour or eight-hour BESS, under conservative scenarios (with high starting costs for solar photovoltaics [PV] and BESS) and realistic scenarios.[xxv] The realistic scenarios include starting costs and design configurations for PV and BESS aligned with norms in many markets with active renewable energy industries today.[xxvi]

As Exhibit 7 shows, the time frame for tightening economics between planned coal and alternatives coincides with a period when many new coal plants are planned. These plants would reach commercial operation at a time when solar with BESS is already cheaper than even the most efficient new coal plants, on a levelized basis. Solar paired with four- or eight-hour BESS alone may not always be a technically viable alternative to all planned coal plants or even be part of the most competitive alternative resource mix. However, this simple comparison underscores the risk that from day 1 of their operation, some planned coal plants may negatively impact customer affordability and national economic competitiveness compared with alternatives.

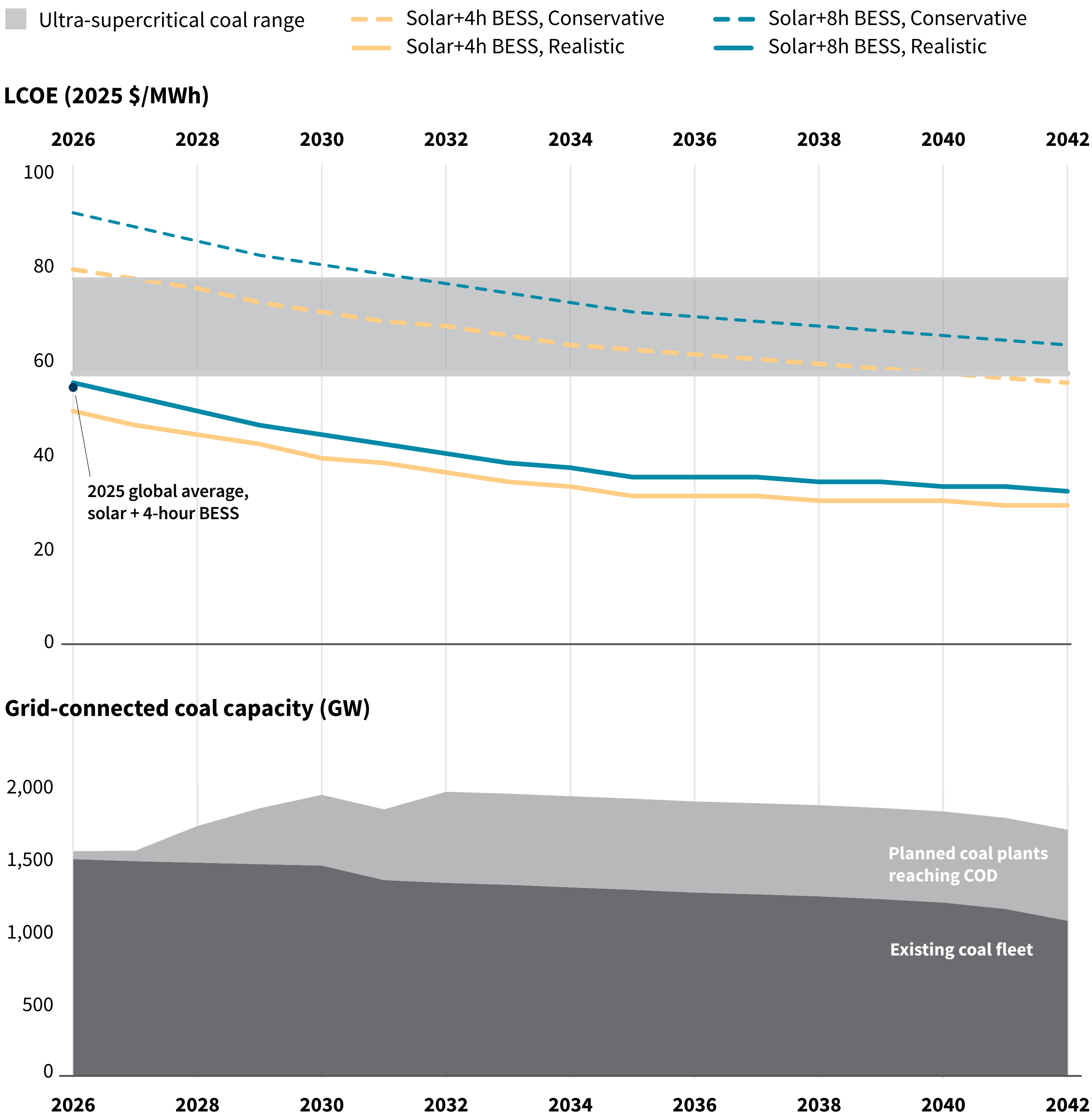
[xxiii] This example is simplified for illustrative purposes, and more detailed study would consider the complementarity of additional technologies to derive a least-cost portfolio, ideally at a system level (e.g., including wind, hydro, gas).

[xxiv] This echoes **recent analysis from the International Renewable Energy Agency (IRENA**) that demonstrates the competitiveness of hybrid renewables-and-BESS systems with new coal in prime resource regions for wind and solar. **World Bank analysis** highlights that while meaningful regional differences remain, the general trend in clean energy costs can create savings opportunities through existing coal plant transition. **Ember analysis** shows that in mid-2025, global renewable energy generation overtook coal generation for the first time.

[xxv] An ultra-supercritical plant is assumed because, as of October 2025, 74% of planned coal plants in the GEM's **Global Coal Plant Tracker** database are ultra-supercritical. Ultra-supercritical plants are on the order of five percentage points more efficient than supercritical plants, and 10 percentage points more efficient than subcritical plants (see *The Future of Coal: An Interdisciplinary MIT Study*).

[xxvi] Conservative scenarios assumed fixed-tilt solar PV, 4.25–4.5 kilowatt-hours per square meter per day (kWh/m^2/day) irradiance, 1:1 PV to BESS power ratio, and a combination of **Ember** and **IRENA** estimates and **NLR learning curves** for projections. Realistic scenarios assumed single-axis tracking PV, 4.75–5 kWh/m^2/day irradiance, 1:0.6 PV to BESS ratio, and a combination of **BNEF estimates** and **NLR learning curves** for projections. BESS is assumed to be lithium-ion.

Exhibit 7 Comparison of LCOE projections of solar + four-hour BESS, solar + eight-hour BESS, and ultra-supercritical coal, and expected time frame for current LMIC planned coal plants to reach commercial operation, 2026–42



Note: This exhibit illustrates expected time frame for current planned coal plants to reach commercial operation, 2026–42. The illustrative time frame for current planned coal plants to reach commercial operation is based on historical GEM data on coal plant development timelines. RMI assumes all coal plants in the development pipeline reach their commercial operation date (COD) on a reasonable timeline with no delays or interruptions. All plants currently under construction are assumed to reach COD in 2026. For other plants, assumed timelines from development stage to COD are as follows: under construction, two years; permitted, four years; pre-permitted, five years; and announced, seven years.

RMI Graphic. Source: RMI analysis, 2025 global data from Bloomberg New Energy Finance

Over time, the risk of locking in these plants becomes even more stark. In 2040, there may be over 500 GW of coal capacity that still has 30 years or more of life remaining but for which the total cost of power (inclusive of capital recovery and fuel) is up to double the cost of a solar and eight-hour BESS alternative.[xxvii] Because those plants are likely to be insulated from competition once they begin operation by long-term contracts or utility tariffs, this represents a significant cost burden to customers and/or taxpayers.

In addition to considering alternative technology costs, considering modularity may be equally important. Resources that can be built rapidly in smaller-capacity tranches may enable decision makers to take advantage of the rapid pace of innovation and cost declines while also being more responsive to evolving grid needs.

Subsequent phases enable deeper analysis before reaching a decision to proceed. As Exhibit 6 shows, if the results from Phase 1 provide a reason to question whether the planned coal plant is the best solution for customers, the next step is to conduct a detailed prefeasibility study.

This process may reveal that there are assumptions that have changed and can readily be updated. It may also find that there are systemic challenges to implementing planned coal alternatives to be overcome (e.g., through regulatory intervention) or more nuanced technical considerations around transmission stability that must be taken into consideration (e.g., via a feasibility study). These steps should go beyond financial and techno-economic considerations to include engaging communities early and regularly. This will differ depending on the situation and entity driving the process.[xxviii] Regardless, accounting for socioeconomic impacts is a critical consideration before reaching a decision.

Engaging in this process presents minimal risk to regulators, utilities, and plant owners. Based on RMI's experience, confidentially exploring alternatives does not imply making any commitment to changing plans unless they provide a "win" for all stakeholders.

[xxvii] In 2040, under all but the most conservative estimates for solar and BESS, solar paired with four-hour or eight-hour BESS outcompetes ultra-supercritical coal. Solar+BESS projects could be between 40% and 110% of new coal project costs in 2040.

[xxviii] For example, plant owners may need to protect commercial interests by avoiding publicizing potential changes to planned projects, whereas a government body may be able and obligated to engage stakeholders more transparently at an earlier stage.

Conclusion: Implications for Decision Makers

The rapidly evolving global landscape suggests that many planned plants warrant reexamination. Electricity systems around the world are rapidly changing amid increasing uncertainty. Meanwhile, the combination of continued planned coal development, evolving grid needs, and a transforming landscape of energy generation technologies is creating both opportunities and risks for power sector decision makers seeking to provide affordable and reliable power that supports economic prosperity and energy security in their countries. There is a clear window to reexamine planned generation, particularly coal, to determine whether these projects still provide the best outcomes for stakeholders.

Significant win-win opportunities likely exist in transitioning planned plants to alternatives. We encourage regulators, planners, owners, and other stakeholders to use the framework provided in this brief as a starting point for identifying planned plants that should be reconsidered. Not all planned coal plants will necessarily become cost burdens, and there may be many plants that remain the least-cost, best solution for their situation.

However, the risk of locking in customers and taxpayers to higher costs is significant, and likely warrants investigation. Proceeding with uneconomic plants risks locking in long-term negative affordability impacts, with plant lifetimes of 40 years or more. Even if planning assumptions and decisions were well vetted and logical 5 or 10 years ago, these analyses may no longer be credible under today's realities. Alternatives to these projects may provide cost savings to customers as well as better returns for developers, and potentially increased energy security at a national level.

Support can facilitate deeper study, and development finance may be able to help unlock certain projects. Where governments, plant owners, or other stakeholders are interested in further analyzing a planned plant or power system, philanthropic aid and development finance can help bridge fiscal gaps for the cost of those studies. For investors and development finance agencies, there may be clear opportunities to support the transition of planned coal to clean alternatives. Where alternatives are already more competitive, these projects may benefit from attractive commercial finance. Other projects may face a viability gap, for example, where sunk costs are greater, if there is forgone revenue, or if storage needs are large, and might be made possible by the introduction of development finance to help overcome those barriers.

Although this brief provides a conceptual starting point, future publications will provide analysis based on real-world experience. Reexamining planned plants is one of several steps on the path to making the decision to transition an asset. In subsequent briefs, RMI will share illustrative techno-economic analyses about the viability of transitioning specific plants and explore regulatory strategies to support implementation. These resources will provide a detailed look into the technical and economic considerations for alternatives to specific plants, and pathways for executing a transition.

As a first step, we encourage readers to apply the framework provided here against planned coal projects in their jurisdiction to begin identifying those that might be candidates for reconsideration. If support is desired in applying this framework or in conducting detailed prefeasibility analysis, RMI and partners are available to provide it — please contact plannedpower@rmi.org.

Appendices

Appendix A: Details on Framework Indicators

The appendix below includes detailed considerations for evaluating Indicators 3, 4, and 5. RMI did not include additional information on Indicators 1 and 2 because they are straightforward to evaluate.

Indicator 3: Sunk costs and obligations associated with plant

Looking at a project's full life cycle shows why reconsidering earlier is most cost-effective. Until a plant has reached commercial operation, it remains conceivable to transition to an alternative. However, the "lock-in" that may need to be accounted for increases as a plant progresses through its development cycle — some of this is capital that has already been invested (or would have to be spent to exit existing agreements), some is related to the promise of future revenue, and the rest is psychological. Three primary factors are important for preliminary consideration of a planned plant:

- **Sunk costs.** These are defined as the cumulative capitalized development and construction costs a planned plant incurs as it is developed. These costs may have been accrued by a coal project that is already in the development pipeline because there has likely already been some capital investment that cannot be easily recovered (e.g., acquired land, purchased equipment, constructed plant infrastructure).

- **Contractual obligations.** These relate to contracts that support the development and future operation of the plant, and typically have fees or penalties associated with their amendment or termination. Examples include PPAs, FSAs, and EPC contracts.

- **Expected future revenues.** These are relevant for coal plants owned by independent power producers (IPPs) and financed at the project level. They represent the forgone future revenues of the coal plant from selling its grid services that the IPP may want to recoup in some manner to transition the planned coal plant. Depending on specific contractual language, there may be instances where contractual obligations partially or fully include recouping forgone future revenues.

These three factors, constituting illustrative plant value in Exhibits A1 and A2, are important in considering the costs of transitioning a planned coal plant. However, other costs contingent on market structure, plant ownership, or the unique circumstances of the project may also be incurred. As Exhibit A1 illustrates, in a typical power project, plant value grows as it progresses in the development pipeline, peaking at commercial operation date (COD), and declining over its operational lifetime. Transitioning a plant at later stages of development — or once it is operational — may require surmounting additional barriers or higher costs.

Locked-in value grows significantly as planned plants reach construction. Looking specifically at the development portion of the life cycle of a planned plant (coal or otherwise), the accrual of locked-in plant value is nonlinear. As Exhibit A2 illustrates, there are significant jumps in locked-in value that occur at specific milestones in the life cycle. There are four main stages of the project development pipeline to consider:[xxix]

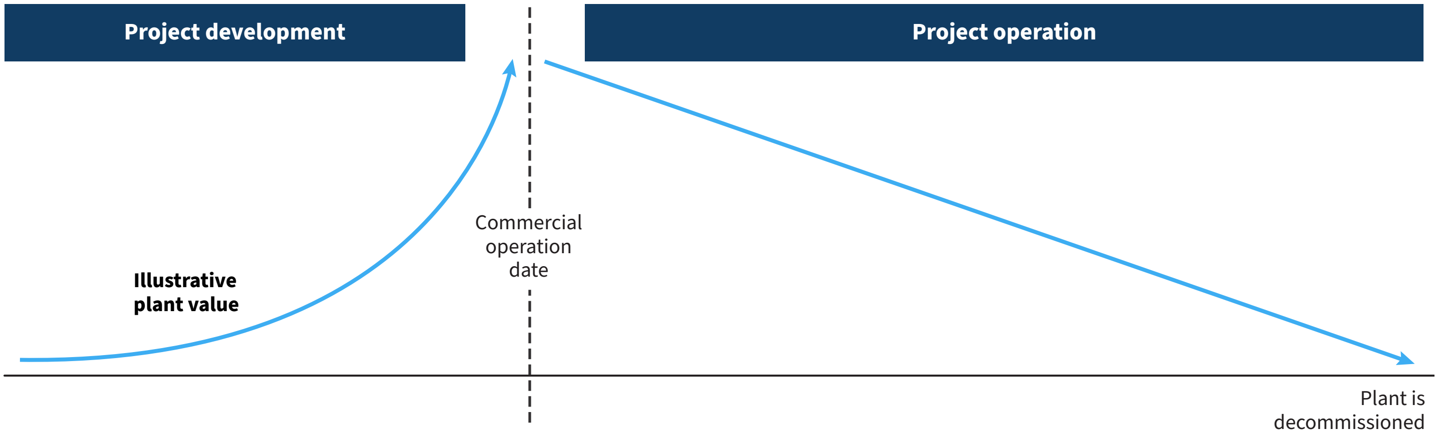
- **Announced:** Projects that are publicly identified in corporate, planning, or government documents that have not yet undertaken concrete steps to move forward in the development pipeline.

- **Pre-permit:** Projects actively pursuing development steps (e.g., acquiring land, applying for environmental approvals, conducting technical studies) before permits are granted.

- **Permitted:** Projects that have received all necessary approvals required to start construction, but physical construction has not yet begun.[xxx]

- **Under construction:** Projects where site preparation and construction activities are underway.

Exhibit A1 **How coal plant value evolves as the plant is developed, begins operation, and is decommissioned***



*This exhibit has been simplified for illustrative purposes. Coal plant value decreases over time until the asset is fully depreciated. The evolution of this value over development and operation varies significantly by the type and terms of financing, the nature of contractual obligations, and more.

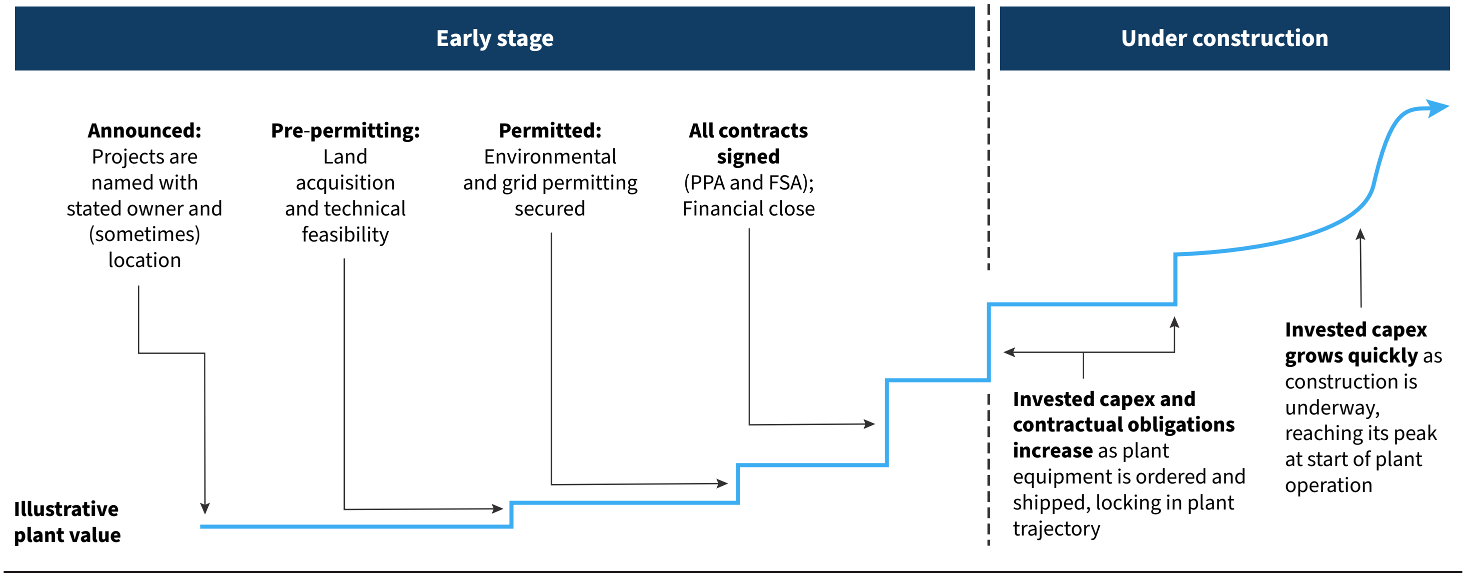
Note: Coal plant value is defined to include costs that need to be recouped (i.e., due to sunk costs or contractual obligations) and any additional compensation for coal plant owners who forgo future revenues.

RMI Graphic. Source: RMI analysis

[xxix] Although terminology is not standardized across the industry, these stages align with definitions in the Global Energy Monitor's Global Coal Plant Tracker.

[xxx] The project is also unlikely to have achieved "financial close" at this stage, or have a legally binding contract in place.

Exhibit A2 How coal plant value evolves during project development



RMI Graphic. Source: RMI analysis

The ideal time to reconsider a plant is before major capital costs are incurred. As Exhibit A2 shows, across these stages, a plant accrues limited value until signing contracts that commit to major costs (e.g., FSAs) and assurances of revenue (e.g., PPAs). This typically occurs around the time that a project has been permitted, and construction has yet to begin or is at early stages. Prior to this point, in the announced, pre-permitting, and early permitted stages, there is increasing expectation of future revenues that increases the project's value to the owner, but it is not yet bankable.

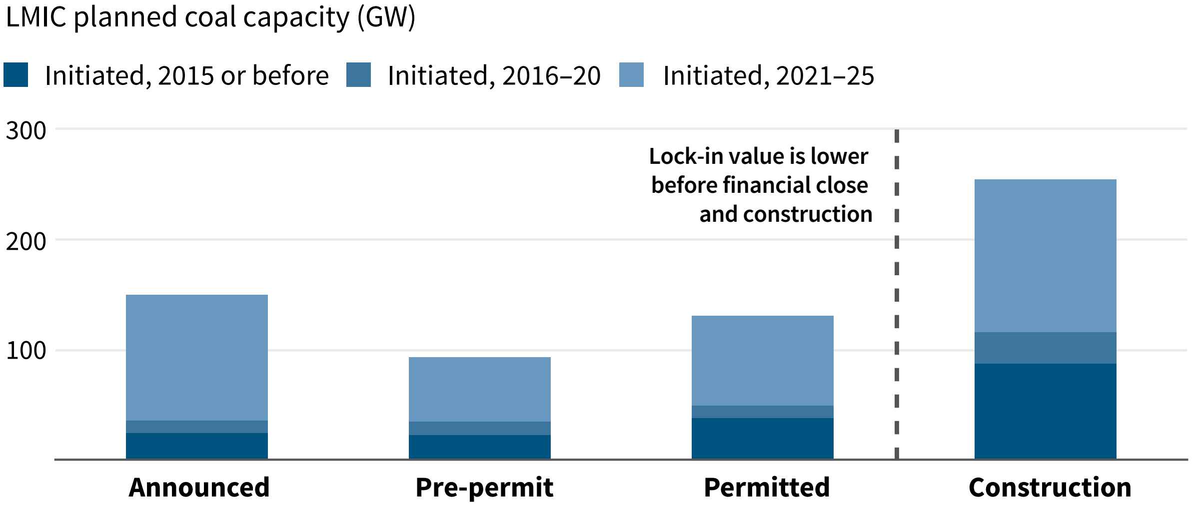
In the period between signing these contracts and commencement of significant construction works, transition remains easier but potentially with additional costs (e.g., penalties to exit contracts). These penalties may be substantial depending on the situation, but solutions exist to mitigate them.[xxxi] Beyond the financial value, inertia to alter a project's trajectory also tends to grow as more time is spent on a project's development, vendors are engaged, and land and permits are acquired. This cognitive bias or inertia should also be considered as a potential barrier to transitioning planned coal plants at later stages of development.

Globally, most planned plants are still in earlier development stages. Considering the above, as power sector decision makers reconsider planned coal plants, there is clearly an opportunity to begin with earlier-stage projects. As Exhibit A3 shows, 370 GW of plants are in the early stage of development (i.e., at announced, pre-permitting, and permitted stages) and are in a "sweet spot" for reconsideration. Of the 370 GW, about 85 GW were first planned more than a decade ago. This subset of plants likely has lower lock-in value but also, as following sections explain, may not be best positioned to meet grid needs anymore if what they were originally designed for no longer aligns with grid needs.

[xxxi] RMI's *Unlocking Coal Contracts* series includes various legal and financial solutions to transition coal plants under contracts while enabling affordable replacement power.

Although 370 GW of early-stage planned coal plants have less lock-in value and potentially the most compelling economic case to transition to alternatives, under-construction plants are also worth reconsidering. For example, of the 250 GW of plants under construction, about 90 GW were initiated more than a decade ago. This may indicate that they are stalled and there could be extenuating circumstances that may lead to the owner being interested in alternatives (potentially discounting the nominally locked-in value of the asset).

Exhibit A3 **Breakdown of LMIC coal pipeline by stage of pipeline, initiation year**



RMI Graphic. Source: GEM, *Global Coal Plant Tracker*

Indicator 4: Role plant was designed to play

Coal plants have typically been designed to play a baseload role on the grid. Historically, most coal-fired power plants have played a baseload role, running close to continuously at their nominal capacity. This is due to both the cost profile and operational characteristics of coal-fired generators. The efficiency of these generators declines at lower utilization rates and due to thermal limitations, which constrains the generators' ability to quickly ramp to follow load or regularly cycle online and offline. Such plants — if situated in a market where they can be project financed — often include PPA contract terms that require a high utilization rate, such as take-or-pay clauses or high minimum offtake.[xxxii] As grids evolve, there is increasing interest in operating coal plants more flexibly as mid-merit or intermediate resources.[xxxiii] This role generally involves providing intraday flexibility to follow predictable load patterns with moderate ramping requirements.

[xxxii] For example, RMI's report *Unlocking Coal Contracts* examined coal plants under PPAs in Indonesia and found that they may need to operate at or above an 80% capacity factor or face significant penalties. PPAs typically include terms for energy (defined by a high minimum capacity factor), capacity (defined through availability criteria), and ancillary services (through either embedded operational criteria or separate contract terms). Flexibility is often reflected through operational parameters and constraints (e.g., ramp rate limits). Heat may be included for CHP plants.

[xxxiii] For more information, read the Coal Transition Commission's *From Flex to Phase-Out* **report.**

Many planned coal plants today can operate more flexibly, but less so than alternatives. At a global level, it is challenging to determine the intended role of planned coal plants based on publicly available documents, and this is best evaluated at an individual plant level. The bulk of today's LMIC planned coal pipeline is ultra-supercritical plants (comprising 77% of the 630 GW pipeline, or 480 GW) that operate more efficiently than existing subcritical and supercritical plants and can ramp up operations more rapidly.[xxxiv] Power sector decision makers have sought to leverage these capabilities, and in some instances have stipulated stricter flexibility requirements for newer coal plants, as is the case in China.[xxxv] However, even in the best case, ultra-supercritical coal plants are not as flexible as gas-fired combined-cycle gas turbines (CCGTs) and are far less flexible than BESS. Coal plants have slower ramp rates, reduced efficiencies at lower utilizations, more limited cycling capabilities due to thermal stress limitations, and higher minimum loads that set the floor for operation.[xxxvi] Some coal plants are also used to provide flexibility at a longer timescale, for instance, providing seasonal balancing in response to weather patterns like monsoon or changes in hydro output levels.[xxxvii]

Coal plants designed to recoup costs through baseload operation may be less economically competitive if used as mid-merit assets, especially compared with alternatives. If coal plants were designed to provide baseload power, then their economics are oriented around a high anticipated annual capacity factor (e.g., on the order of 75%–85%). If the grid no longer needs additional baseload capacity, this will result in either the new coal plant operating at a lower capacity factor than intended, or reducing the capacity factors of other existing plants (Exhibit A4). Regardless, either the new plant or an existing plant(s) would be forced to recover its capital costs over less energy produced, raising customer costs on a levelized basis or resulting in reduced revenue for the owner. This would be true even if the coal plant is ultra-supercritical and capable of more flexible operation.

The impact of such a situation may be significant given the size of the assets involved and the magnitude of capital costs to recover (and what are typically inflexible contractual arrangements). These higher costs may be incurred through higher-than-needed PPA payments and ultimately compensated through customer utility bills that facilitate the plant's capital recovery, or even through subsidies provided by taxpayers. This is a particular risk in geographies where existing baseload coal plants are already not operating at typical baseload capacity factors. For example, in India and China, coal fleets are noted to be operating at average capacity factors of **66%** and **48%** in 2025, respectively, with China's having fallen from 60% in 2011.

---

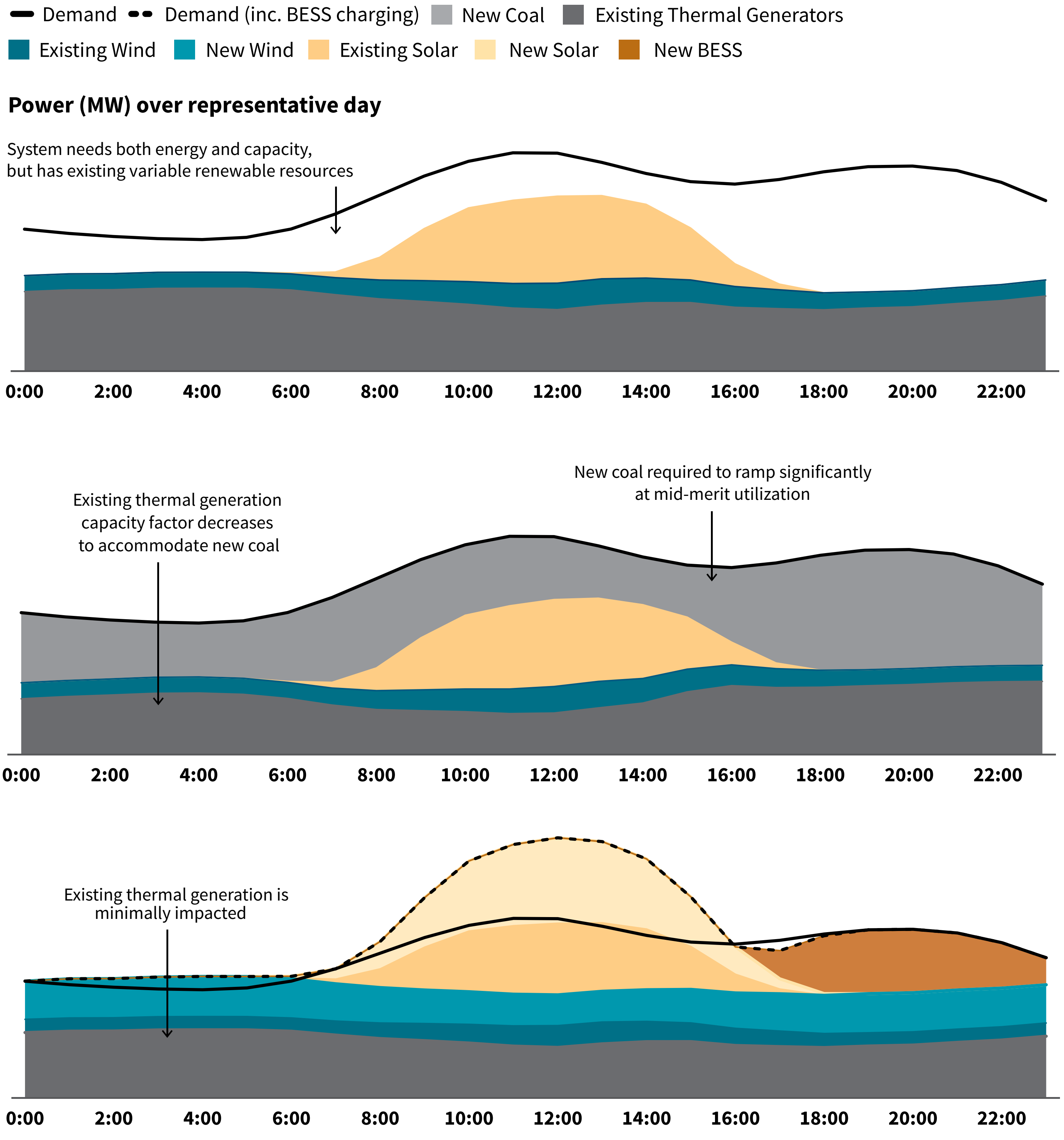
xxxiv Data is sourced from GEM's **October 2025 release.**

xxxv China has **imposed several flexibility requirements on its coal plants**, including reducing minimum stable load to 25% of rated capacity, and a ramping rate of 2.2% of rated capacity per minute for loads exceeding 50%.

xxxvi Coal plants typically have a minimum operating level of **40% of nominal load but can go as low as 25%**. They ramp between **1% and 4%** nominal capacity/minute (which can **go up to 8%**) but are constrained in **frequency and degree of cycling by thermal stress**. CCGTs have similar minimum loads but can operate at as low as **15% of nominal load**. They operate at **2% to 4%** nominal capacity per minute, but can **go up to 15%**. BESS **ramps nearly instantaneously** and does not have mechanical constraints to cycling (though it does accelerate battery degradation).

xxxvii However, plants do not usually need technical modifications to play this role. For more details, see the Coal Transition Commission's *From Flex to Phase-Out* report.

Exhibit A4 Illustrative system dispatch for a system with existing thermal resources, showing the impacts of adding variable renewable resources or new coal



System needs both energy and capacity, but has existing variable renewable resources

Existing thermal generation capacity factor decreases to accommodate new coal

New coal required to ramp significantly at mid-merit utilization

Existing thermal generation is minimally impacted

RMI Graphic. Source: RMI analysis

Indicator 5: Evolution of grid needs since plant was planned

What a grid needs today and in the future often differs significantly from what it needed years ago. Although a coal plant may have been designed for a specific role, the grid's actual needs today and into the future may have changed. Particularly for plants that have been under development for an extended period, our work has often found significant differences between evolving grid needs and original plant design. Two major reasons stand out:

1. **The makeup of grids is changing rapidly**. As noted above, the economics of new technologies have fundamentally shifted the choices available to stakeholders in a grid. As they choose to adopt these technologies, it is similarly shifting the operational dynamics of these grids. For example:
    - The shape of systems' net load is changing as behind-the-meter resource adoption increases. In some places this is happening slowly (e.g., **Indonesia**) but in others it is happening nearly overnight (e.g., **Pakistan**).
    - The mix of grid-connected resources is changing, with more variable renewables, more storage, more inverter-based resources, and dynamic fossil fuel supply chains. This exacerbates changes in the shape of the system's needs.[xxxviii] The IEA's ***Integrating Solar and Wind in Southeast Asia*** report describes how solar-dominant countries today are already seeing impacts on system net load, and these are emerging in countries like Indonesia, Thailand, and Vietnam (see Exhibit A5).
2. **Planning assumptions become quickly outdated**. As the saying goes, all forecasts are wrong; some are useful. But even the most robust planning analyses are less likely to track reality as time progresses and uncertainty rules the day.[xxxix] In the case of coal plants, many have been under development long enough that reasonable assumptions — made when they were planned or procured — are no longer accurate.[xl] This can happen for a variety of reasons, such as load growth deviating from expectations, new market entrants, unplanned capacity procurement, or the extension or early retirement of other generators. This can particularly include assumptions about where load growth will occur, and where transmission congestion is or is not expected.

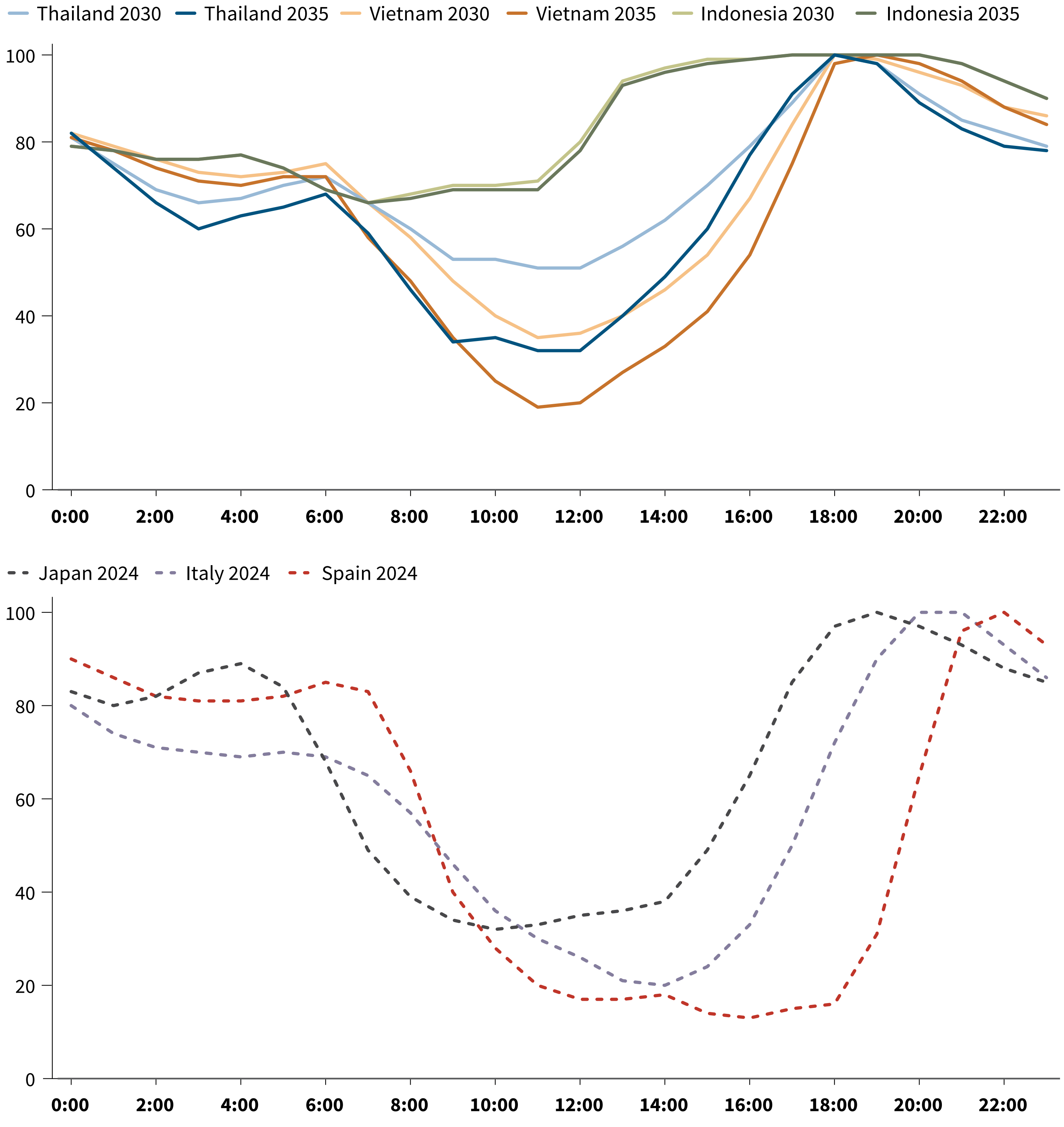
[xxxviii] Globally, clean energy accounted for **80% of total growth in electricity generation** in 2024. Solar PV led the way, with close to 500 terawatt-hours (TWh) in incremental generation.

[xxxix] RMI **tracking of US utility plans**, for example, shows how they have varied significantly in planned capacity and generation over the years, while *Power System Planning in an Uncertain World* (forthcoming) provides improved approaches to identifying least-regrets decisions.

[xl] Per GEM, more than 220 GW of grid-connected planned coal plants have been under development pre-2020.

Exhibit A5 IEA analysis of net load curves in various Southeast Asian countries in 2030 and 2035, and select solar-dominated systems in 2024

Net load % (normalized by peak net load) across representative day



RMI Graphic. Source: IEA, *Integrating Solar and Wind in Southeast Asia*, 2025, License: CC BY 4.0

Modern grids need increased flexibility, which may not align well with planned coal plants' capabilities. As grids modernize, gone are the days when baseload power was a reliable way to think about future capacity needs. As Exhibit A5 illustrates, the evolving shape of net load means that the grid needs fast ramping capacity and generation in the morning and evening hours. Many grid planners are actively modernizing their approaches to account for these trends, and for how to plan in an era of increasing change. For example, planners may consider reliability in terms of resource adequacy, operational reliability, and resilience, rather than in terms of simplified baseload or mid-merit generation. This requires taking into consideration dynamics on the broader grid, not just an individual plant, across a wide range of system conditions and contingencies.

As noted above, determining the precise grid needs in a specific situation is a significant analytical undertaking. In lieu of that, to consider alternatives to a planned coal plant, answering a few key questions can provide a proxy:

- **Do current system plans call for more generation capacity with the operational cost structure and flexibility capabilities of this plant?** National and/or utility planning documents, even if imperfect, can provide directional insight into the capabilities the grid needs more of.

- **Do market prices indicate an oversupply or undersupply of certain services?** Beyond planning documents, where competitive markets exist, trends in bid volumes and prices for specific products can indicate what the grid most acutely needs.

- **Have there been major changes in the supply mix since the plant was conceived?** Recent announcements of changes in other generation assets can indicate a system where grid needs are evolving, including both accelerated retirements and extensions of existing plants, and the pace of other capacity additions.

- **Is the system's net load profile significantly evolving?** As behind-the-meter resources and zero- or low-marginal-cost variable renewable generation are integrated (or projected to increase), they reshape the net load curve of the grid, which indicates a likely need for flexible resources rather than inflexible ones.

- **Are grid congestion patterns changing or is concentrated demand growth expected?** If the locational dynamics between supply and demand are evolving, they may or may not align well with the location of the planned coal plant, but may also indicate a need for more flexible procurement and less-concentrated deployment.

Answering "yes" to one of these questions is a good indicator that alternatives may align well with the grid's needs. Alternatives being less well aligned does not mean they are not technically viable — rather, as discussed above, it might mean that they would require greater investment (e.g., to increase storage capacity), additional study to understand broader system integration dynamics, or changes in regulation to enable certain technologies to be used (e.g., BESS) or their ancillary benefits to be valued.

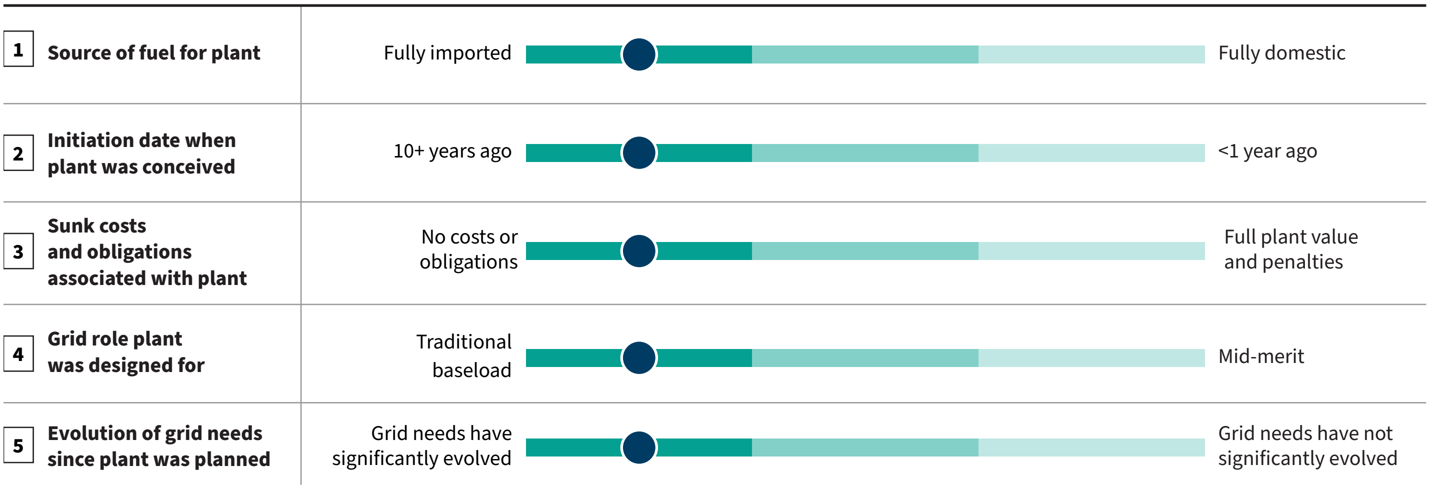
Appendix B: Applying the Framework

Examples of using the framework for initial assessment

As discussed above, coal plant build-out is continuing to occur for a variety of reasons, ranging from cost competitiveness to energy security concerns to legacy planning and procurement assumptions. Every coal-fired power plant is unique, and altering any development plans warrants detailed study. However, for decision makers considering alternatives to planned coal plants, the simplified framework introduced earlier can inform which plants to prioritize.

The following three plant examples reflect real-world coal plant and market dynamics, and considerations for assessing alternatives to them. These considerations map to Phase 1, Step 1 of the assessment process outlined in Exhibit 6.

Exhibit B1 Applying framework to Example 1, subcritical plant planned long ago



RMI Graphic. Source: RMI analysis

Takeaway: Plants similar to this profile should be a high priority to reconsider.

Plant and grid context:

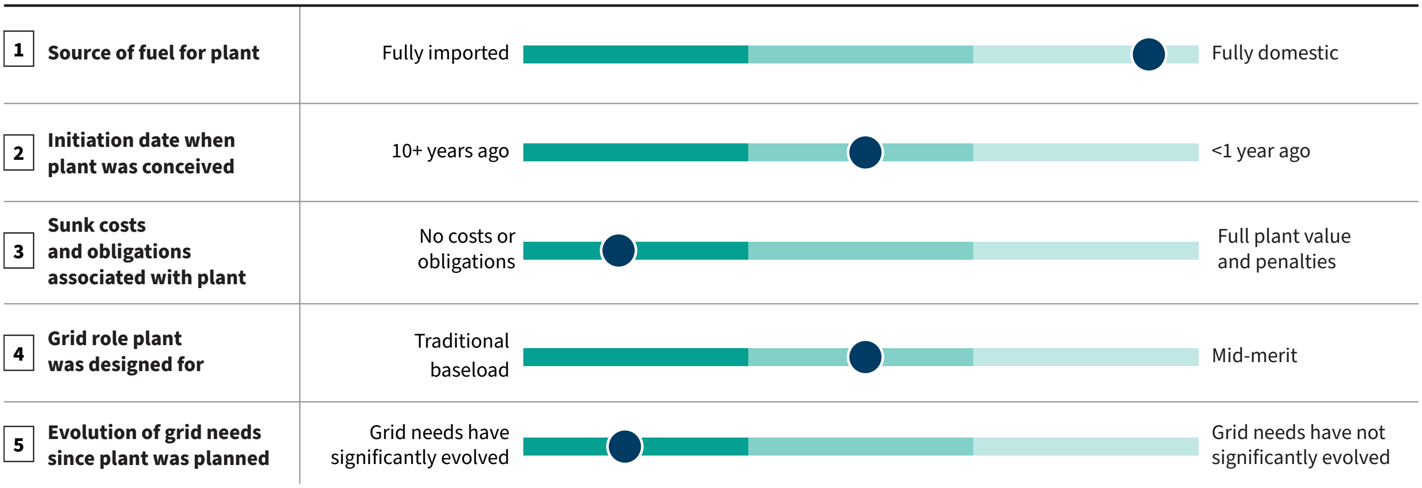
- This is a subcritical plant initiated a decade ago in a country where all coal is imported.
- The plant has a signed and active PPA in place with a local utility but has not yet reached financial close or begun construction. It has limited contractual obligations and sunk costs.
- When the plant was planned, it was originally designed to play a traditional baseload role.
- Since then, the utility's load and procurement of other generators have evolved and it requires flexible dispatch akin to mid-merit generation.

Applicability of Example 1 to LMIC coal pipeline: Although only 3% (or 16 GW) of the LMIC coal pipeline consists of subcritical plants, more than 28% of the pipeline (over 170 GW) includes coal plants that were first conceived a decade or more ago.

Implications and next steps for considering alternatives

- **Implications for plant** — *Higher priority to reconsider.* As Exhibit B1 shows, all indicators point to this plant no longer being the least-cost resource to meet the grid's needs. It is likely that alternatives will be lower cost, and transitioning the planned coal plant to its alternative can occur with commercial financing.
- **Next step** — A high-level assessment of economic competitiveness (i.e., Phase 1, Step 2 from Exhibit 6) is likely to yield a strong case for an alternative. If that materializes, a prefeasibility study to assess alternatives to the plant may support making a final decision.

Exhibit B2 Applying framework to Example 2, ultra-supercritical plant sited near high variable renewable resource deployment



RMI Graphic. Source: RMI analysis

Takeaway: Plants like this should be a high priority to reconsider, with additional support potentially needed to leverage concessional capital.

Plant and grid context:

- This is a supercritical coal plant that was planned in 2019, in a country with large domestic coal resources.
- The plant has a signed PPA in place and has reached financial close but not yet begun construction. It has contractual obligations if the PPA were modified or terminated.
- Since the plant was planned, the local grid has seen significant deployment of solar, which increasingly drives daytime generation dispatch.
- Although additional capacity is still needed on the grid, it is increasingly needed only during the evening hours as solar ramps down and demand rises.

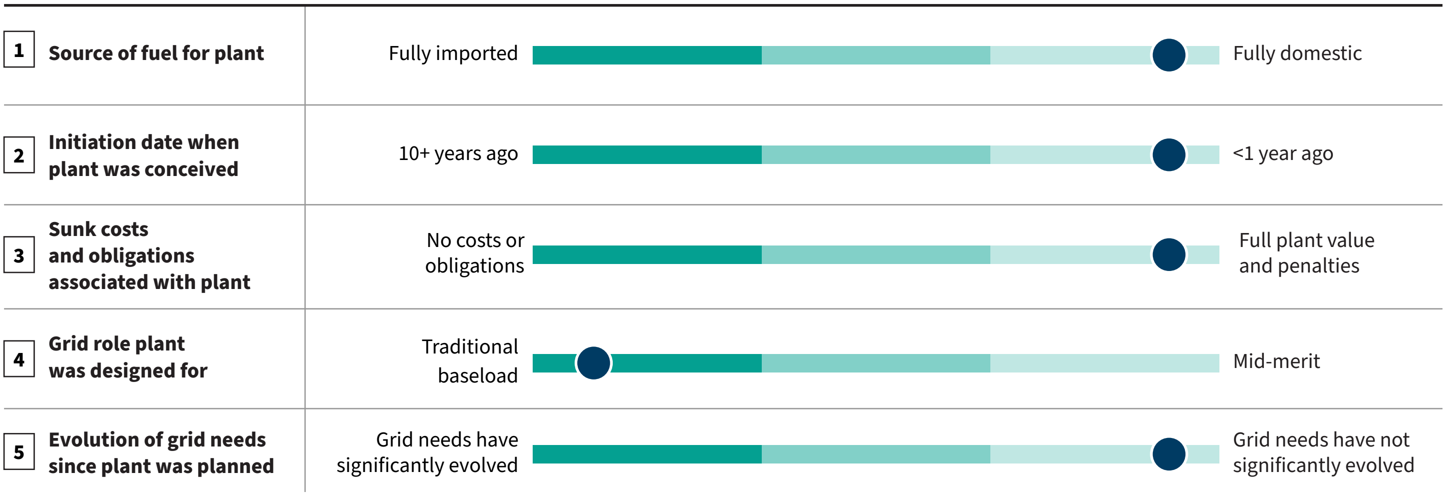
Applicability of Example 2 to LMIC coal pipeline: More than 11% of the LMIC coal pipeline (70 GW) is supercritical, and over 35% of it (220 GW) was initiated before 2020. Of the 70 GW of planned supercritical coal plants in LMICs, 67 GW are in countries that have seen significant growth in and penetration of solar (China, India, Pakistan, Philippines, Vietnam)

Implications and next steps for considering alternatives:

- **Implications for plant** — *Higher priority to reconsider with support*. Alternatives may be lower cost and a better fit for grid needs compared with this plant, but if these needs still require a relatively high-capacity factor resource, it may increase alternative costs by requiring more storage capacity (see Exhibit B2). Along with contract modification penalties, concessional capital might be required to overcome a viability gap.

- **Next step** — After assessing high-level economic competitiveness, a prefeasibility study that combines capacity expansion and production cost modeling with project finance modeling will be helpful. The former will support understanding grid needs more granularly and under various sensitivities (e.g., demand growth, fuel and technologies prices), while the latter can help identify a financial viability gap (if it exists) and test ways to address it.

Exhibit B3 Applying decision framework to Example 3, under-construction plant providing needed baseload



RMI Graphic. Source: RMI analysis

Takeaway: This type of plant would likely be a lower priority to reconsider, relative to other plants, or could be reevaluated as part of a system-wide planning analysis.

Plant and grid context:

- This is an ultra-supercritical plant that was initiated last year, in a country with significant domestic coal resources.
- It has meaningful sunk costs and contractual obligations as the plant has reached financial close with a PPA, has an FSA, and is midway through construction.
- The coal plant is designed to fulfill a traditional baseload role on the grid, which needs it for the foreseeable future.

Applicability of Example 3 to LMIC coal pipeline: Of the 260 GW of LMIC coal plants initiated in the past two years (2023–25), around 50 GW are currently under construction.

Implications and next steps for considering alternatives:

- **Implications for plant** — *Lower priority to reconsider.* This plant is very likely still the most competitive option for its situation based on economics and grid needs (see Exhibit B3).

Assessing high-level economic competitiveness

As the assessment process in Exhibit 6 outlines, after directional alignment using the decision framework in Phase 1, Step 1, power sector decision makers are advised to conduct a high-level assessment of economic competitiveness of the planned plant against an alternative (Phase 1, Step 2). This section outlines how a utilization-adjusted LCOE comparison can be conducted and the emerging technology trends that are creating more competitive alternatives to planned coal in many situations.

LCOE provides a sufficient starting point to compare the competitiveness of planned coal against potential alternatives. The economic competitiveness of planned coal against alternatives is an indicator of value — an uncompetitive coal plant means that unnecessary costs are being imposed on customers, or that plant owners are forgoing potential returns.

To determine competitiveness across various options and different technologies, begin by considering the grid needs that must be met: What is required of the resource? Linking grid needs to project design and costs becomes an iterative process with deeper study, but high-level assumptions about the flexibility (how quickly and frequently must it ramp?) and utilization (how often is it required to run and at what portion of its capacity?) required of the resource — whatever its technology — can provide a reasonable starting point for comparison.

As discussed above, LCOE provides a simple metric for preliminary economic comparison. Although LCOE does not capture project revenue or system cost savings, it is reasonable to ignore these in a preliminary comparison to determine whether a plant should be reconsidered.[xli] Further analysis of the specific situation can calculate system cost impacts and explore whether differentiated revenue opportunities exist between technologies.[xlii] To simplify preliminary consideration, it is also appropriate to assume equivalent cost of finance between planned coal and an alternative, though again, this should be examined in detail at future stages.[xliii]

The costs and capabilities of planned coal plants have remained largely static. On one side of this comparison, coal plant capital costs have not changed significantly in recent years and **are not expected to**. As discussed previously, modern plants tend to be more flexible and more efficient than older plants, but not dramatically so. **There are efforts to boost the efficiency of ultra-supercritical plants by several percentage points**, but this may only be realized in the medium term, at best. The performance of even the most advanced coal plants meaningfully degrades at lower utilization rates, which is becoming increasingly common for coal plants around the world as grids require greater flexibility.[xliv]

[xli] This assumption means that contract terms (e.g., PPA) and/or market participation are equivalent between both resources. In practice, this may not always be the case. Generally, experience has shown that offtakers are technology agnostic (or, if anything, prefer cleaner generation sources), markets either are or are becoming open to all technologies, and alternatives can be designed to provide equivalent services to a planned coal asset.

[xlii] For example, some alternatives may have opportunities to earn additional revenue through policy compliance (e.g., renewable energy certificates) or providing additional market services outside of the existing contract (e.g., leveraging spare BESS capacity for “value stacking”).

[xliii] If anything, it is more likely that an alternative incorporating clean technologies would be better able to access affordable commercial debt, and in some situations may be able to access concessional finance.

[xliv] As an example, the Coal Transition Commission’s *From Flex to Phaseout* report shares a gross efficiency loss of three percentage points for a unit in Poland when its utilization was reduced from 60% to 40%.

Coal fuel costs vary significantly depending on the source and whether they are imported or domestically produced, but in any case, global price benchmarks have not fluctuated significantly in recent years except for global price spikes following Russia's invasion of Ukraine, and, more recently, with the closure of the Strait of Hormuz.

Clean energy technologies have declined significantly in cost and continue to do so. The continued development of coal is occurring amid an inflection point in the costs and availabilities of alternative power technologies. These changes are opening new possibilities for power sector planners as they look to leverage low-cost energy generation from variable renewable energy resources like wind and solar while managing increasingly dynamic system operations using BESS, VPPs, and other novel sources of flexibility like LDES.

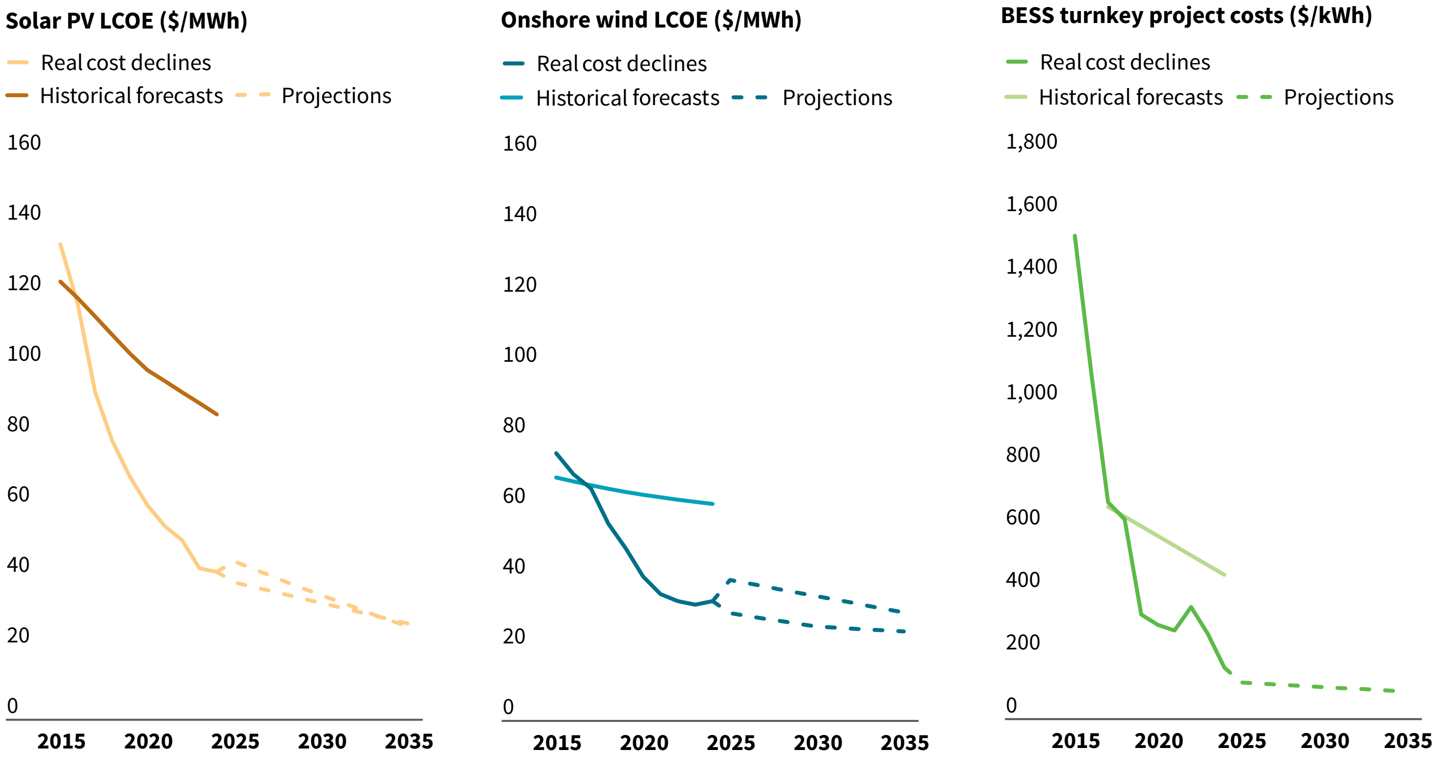
- **Solar, wind, and BESS trends:** As Exhibit B4 shows, solar, wind, and BESS have entered the mainstream of power sector planning, with their costs declining 70%, 55%, and 90%, respectively, over the past decade (2015–24), and all are projected to decline further. As the exhibit shows, historical cost forecasts for these technologies have consistently underestimated the pace and magnitude of declines; planners can be confident these trends will continue. The cost trends on solar, wind, and BESS are translating to massive deployment — for example, installed BESS capacity globally grew more than 50% from 2023 to 2024, and all-in capital costs for BESS projects reached $125/kilowatt-hour (kWh) in late 2025 and continue to fall.

- **Emergence of VPPs:** Meanwhile, emerging approaches like VPPs and technologies like LDES are poised to unlock greater flexibility and help planners utilize and integrate greater quantities of low-cost variable renewable energy resources. VPPs are growing rapidly as well — in North America, the market grew by 33% from 2024 to 2025[xlv] — as advances in digital infrastructure and increasing building and vehicle electrification create more demand-side resources to draw on. RMI analysis of a representative US power system found that a VPP-enabled resource portfolio could achieve a 20% reduction in net generation costs, in part by rightsizing the amount of generation to meet grid needs.

- **Emergence of LDES:** Interest in LDES is growing as well, with pilots and demonstration projects for a range of novel LDES technologies occurring in China, Italy, the United Arab Emirates, and the United States. System planners in the UK and Australia are beginning to incorporate LDES pilots and analytical scenarios into market design, long-term planning, and political targets. Although cost projections for LDES vary significantly by technology and use case, some estimates indicate electrochemical LDES could cost as little as $150/kWh by 2030 in all-in project costs.

[xlv] Market growth is defined as company deployments, unique offtakers, and monetized programs of VPPs.

Exhibit B4 **Trends in global solar, wind, and four-hour BESS costs***



*Solar and wind LCOE forecasts from 2015 are from NLR (solar forecast use 20% capacity factor assumption, wind forecast used TRG4). Projections from 2025–35 are from NLR and Bloomberg New Energy Finance (BNEF). Actual declines in LCOE are from IRENA and are global weighted averages. Four-hour BESS turnkey project cost forecasts from 2017 are from IRENA. The BESS cost projections are from BNEF, and assume a similar future decline in turnkey project costs as in levelized cost of storage. Actual declines in BESS costs are from IRENA and BNEF.

RMI Graphic. Source: Based on data from NLR, BNEF, and IRENA

Portfolios of clean energy technologies are being deployed to meet a variety of grid needs. Cost is one dimension, but a coal plant can provide a range of grid services. Although none of the clean energy technologies noted above can individually replicate those services, in combination they can provide an equivalent suite of capabilities. Specifically, solar and/or wind generation paired with BESS is proving capable of competing with coal- and gas-fired generation in many jurisdictions around the world to provide not only energy, but also capacity for resource adequacy, and a range of ancillary services such as frequency regulation and spinning and nonspinning reserves. These capabilities are being demonstrated in recent projects and procurements:

- For example, in Chile, a 220 megawatt (MW)/1.2 gigawatt-hour (GWh) BESS project was built for grid stability and to provide "sun at night," according to the developer, and has been delivering power six hours after sunset.

- In India, a recent 1,200 MW solar/600 MW BESS auction hosted by the Solar Energy Corporation of India to enable power supply during evening peaks yielded bids in the average range of $40 to $45/megawatt-hour (MWh).

- Looking to secure longer-duration storage, grid operators in Italy, Germany, and Great Britain are competitively procuring for greater than eight-hour storage, with Australia recently securing six projects between 8 and 12 hours duration at an **average capacity cost of ~$140/kWh**.[xlvi] Apart from specific procurements, many grids are updating capacity accreditation mechanisms to account for a resource's ability to provide power when it is most needed.[xlvii]

- Beyond energy and capacity, these hybrid systems are providing a range of ancillary services in many markets. Technological **advancements, such as grid forming (GFM) inverter capabilities,** are enabling support for additional grid stability services (e.g., synthetic inertia) and are increasingly being deployed at negligible marginal cost. For example, **ESIG's GFM database** currently tracks 78 grid-scale GFM projects across six continents, and this list is growing rapidly.

Solar paired with BESS is competitive with new coal on an LCOE basis for many scenarios. Can the combination of these alternative technologies provide an option that is more affordable and equally reliable as a planned coal plant? Detailed plant-level analysis that takes context-specific grid needs into account can conclusively answer this for final investment and planning decisions. But a high-level cost comparison for a generic profile can provide a sense of why many planned coal plants warrant reevaluation.

Exhibit 7 in Section 4 shows an LCOE comparison that includes a range of scenarios for a new ultra-supercritical coal plant against an alternative that includes solar generation paired with either four- or eight-hour BESS.[xlviii] Assumptions for these scenarios are relatively conservative for solar and BESS, and optimistic for coal (see Exhibit B5 for greater detail):

- The range of coal LCOEs represents leading-edge coal plant (ultra-supercritical) costs for baseload and flexible operations in different parts of the world.[xlix] These scenarios are of course imprecise but provide a reasonable illustration for discussion.

- As Exhibit B5 describes, the solar + BESS projections capture high and moderate starting costs for solar and BESS technologies. They also account for different PV technologies, solar irradiances, BESS starting costs, and BESS build-out ratios. These projections are relatively conservative because we are already seeing solar and four-hour BESS projects in the $40 to $60/MWh range in **India** and **globally**.

As Exhibit 7 shows, broadly speaking, solar paired with either four- or eight-hour BESS is economically competitive today with new coal under moderate cost assumption scenarios. Alternatives may be competitive in those situations with more diverse resource portfolios (e.g., integrating VPPs, wind) and in the near future with LDES declining in cost. Under moderate cost assumptions:

[xlvi] Estimated in US dollars, over a 14-year contract (~$10/kWh/year).

[xlvii] For example, the regional transmission organization PJM Interconnection shifted to accrediting capacity based on effective load-carrying capability so that resources are valued for being available in the hours when risk to reliability is highest. **Studies are also showing** solar and BESS with 90% availability during the top 100 highest net load hours of the year.

[xlviii] As of October 2025, 74% of planned coal plants are ultra-supercritical (see GEM's **Global Coal Plant Tracker** for more). Ultra-supercritical plants are on the order of five percentage points more efficient than supercritical plants, and 10 percentage points more efficient than subcritical plants (see *The Future of Coal,* an interdisciplinary MIT study).

[xlix] There is a range of LCOE estimates for ultra-supercritical coal plants. Data and estimates from the Institute for Energy Economics and Financial Analysis (**IEEFA**), US Energy Information Administration (**EIA**), and **Ember** yield a $60–$90/MWh range (corresponding to a 55%–85% range on capacity factors, per IEEFA). RMI chose a $60–$80/MWh LCOE band.

- **Solar + four-hour BESS** is cost competitive with coal today, on an LCOE basis. By 2030, solar + four-hour BESS costs could be 50% to 120% of ultra-supercritical coal project costs, with the former outcompeting the latter in all but the most conservative cost projections. By 2040, those solar + BESS projects could outcompete coal in all projections, with costs as low as 40% of new coal project costs.

- **Solar + eight-hour BESS** is also cost competitive with coal today, on an LCOE basis. By 2030, solar + eight-hour BESS could be 60% to 140% of ultra-supercritical coal project costs. By 2040, solar + BESS projects could be 50% to 110% of new coal projects, reaching close to parity even under the most conservative assumptions.

As alternatives become more competitive, there is a risk that new coal plants quickly become cost burdens for customers. The time frame for the tightening economics between planned coal and alternatives coincides with a period when many new coal plants are planned and if built would result in a new peak for coal capacity across LMICs.

Exhibit 7 also shows the global coal capacity over time, including the addition of planned coal capacity atop the existing LMIC coal fleet (reflecting planned retirements).[l] As the exhibit shows, a significant portion of planned coal projects would reach commercial operation at a time when solar with BESS is already cheaper than even the most efficient new coal plants, on a levelized basis.

Coal plants in the development pipeline, if built, could be retired early and replaced with more cost-effective resources. But this would require sharing savings with plant owners and/or lower expected returns for the owner on their investment — not to mention likely utilizing innovative financing mechanisms to recoup costs. This can all be avoided by building the more cost-effective alternative in the first place.

---

[l] The illustrative time frame for current planned coal plants to reach commercial operation is based on historical GEM data on coal plant development timelines. RMI assumes all coal plants in the development pipeline reach their COD on a reasonable timeline with no delays or interruptions. All plants currently under construction are assumed to reach COD in 2026. For other plants, assumed timelines from development stage to COD are as follows: under construction, two years; permitted, four years; pre-permitted, five years; and announced, seven years.

Exhibit B5 Key assumptions in solar paired with four-hour and eight-hour BESS LCOE projections

	Solar PV Technology Assumptions					BESS Assumptions	
	PV Technology	**Solar PV Starting Cost** ($2025/ kW_{AC})	**Global Horizontal Irradiance (GHI) Bin** (kWh/m²/ day)	**Inverter Loading Ratio**	**Mean Alternating Current (AC) Capacity Factor (%)**[li]	**BESS Starting Cost** ($2025/ kWh)	**PV to BESS Power Ratio** (MW_{AC} PV to MW_{AC}-BESS)
Solar PV + 4-h BESS, Conservative	Fixed tilt	935 (IRENA global average)	Class 7, 4.25–4.5 kWh/m²/day	1.23	18.8%	596 (Ember global average)	1:1
Solar PV + 4-h BESS, Realistic	Single-axis tracking	980 (IRENA global average)	Class 5, 4.75 to 5 kWh/ m²/day	1.34	28.3%	468 (BNEF global average)	1:0.6
Solar PV + 8-h BESS, Conservative	Fixed tilt	935 (IRENA global average)	Class 7, 4.25–4.5 kWh/m²/day	1.23	18.8%	1,072 (Ember global average)	1:1
Solar PV + 8-h BESS, Realistic	Single-axis tracking	980 (IRENA global average)	Class 5, 4.75 to 5 kWh/ m²/day	1.34	28.3%	842 (BNEF global average)	1:0.6

Note: MW_{ac} = megawatt AC current. Developed using NLR's Annual Technology Baseline (ATB) LCOE workbook template. For Conservative scenario, NLR moderate learning curves used for fixed tilt solar, with 33% CAPEX reduction from 2023-2035. NLR-aligned BESS learning curve assumes 38% CAPEX reduction from 2022-2035. For Realistic scenario, NLR advanced learning curves used for single-axis tracking solar, with 58% CAPEX reduction from 2023-2035. NLR-aligned BESS learning curve assumes 54% CAPEX reduction from 2022-2035.

RMI Graphic. Source: RMI analysis of data from NLR, IRENA, BNEF, and EMBER

[li] Although LCOE calculations do not rely on subannual, location-specific data, capacity factors used in NLR's ATB are based on US locations and 2019 weather data.

Selena Kay Galeos, Rachit Kansal, and James Sherwood, Reconsidering Planned Generation, RMI, 2026, http://rmi.org/resources/reconsidering-planned-generation-report.

All images used are from iStock.com unless otherwise noted.

RMI Innovation Center
22830 Two Rivers Road
Basalt, CO 81621

www.rmi.org