System-level impacts of 24/7 Carbon-Free Electricity (CFE)

Results for Taiwan 🇹🇼

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Our methodological approach is focused on the assessment of system-level costs and benefits of 24/7 Carbon-Free Electricity (CFE) procurement in Japan, India, Singapore, Taiwan, and Malaysia. It builds on a robust body of literature and cutting-edge modelling tools.

TU Berlin and affiliated researchers:

- *Riepin, I., & Brown, T. (2022). System-level impacts of 24/7 carbon-free electricity procurement in Europe. Zenodo.* https //doi.org/10.5281/zenodo.7180098
- *Riepin, I., & Brown, T. (2023). The value of space-time load-shifting flexibility for 24/7 carbon-free electricity procurement. Zenodo.* https //doi.org/10.5281/zenodo.8185850

Princeton University (ZERO Lab):

- *Xu, Q.,Manocha, A.,Patankar, N., and Jenkins, J.D., System-level Impacts of 24/7 Carbon-free Electricity Procurement, Zero-carbon Energy Systems Research and Optimization Laboratory, Princeton University, Princeton, NJ, 16 November 2021.*
- *Xu, Q., & Jenkins, J. D. (2022). Electricity System and Market Impacts of Time-based Attribute Trading and 24/7 Carbon-free Electricity Procurement. Zenodo.* https //doi.org/10.5281/zenodo.7082212

International Energy Agency (IEA):

- *Regional insights and sectoral analyses*
- *IEA (2022), Advancing Decarbonisation through Clean Electricity Procurement, IEA, Paris.* https //www.iea.org/reports/advancing-decarbonisation-through-clean-electricity-procurement

Our in-house modelling leverages PyPSA (Python for Power System Analysis), an open-source framework for simulating and optimizing energy systems. This platform enables high-resolution, hourly modelling of decarbonised power systems, adapted for our country-specific analyses. We are grateful to all contributors in the open modelling community, whose tools and insights strengthen the analytical foundation for achieving global CFE goals.

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Foreword

In December 2024, the Taiwanese government strengthened its Nationally Determined Contribution (NDC), raising its 2030 emissions reduction target from 24% ± 2% to 28% ± 2% below 2005 levels. This is an encouraging signal of commitment, particularly given concerns that earlier renewable energy targets may be slipping out of reach. After committing in 2016 to raise renewables to 20% of total generation by 2025, the government postponed this deadline to late 2026 in its March 2022 strategy update, Taiwan's Pathway to Net-Zero Emissions in 2050. As of September 2025, uncertainty remains over whether even this revised timeline will be met. In this context, the strengthened decarbonisation pledge is a timely and positive development, aligning with growing corporate interest in clean energy worldwide. As Asia's ninth-largest economy, Taiwan has a per capita income higher than many of its regional peers and holds a globally dominant position in the semiconductor industry. Decisions made in Taipei therefore carry significant weight, influencing the ability of technology leaders around the world to transition to cleaner business models. Taiwan, therefore, faces both opportunities and challenges as it transitions to an electricity grid increasingly powered by low-cost, variable renewable energy (VRE).

At the heart of this transition is Taiwan's ability to generate 24/7 carbon-free electricity (24/7 CFE) at scale, meeting the expectations of international consumers who purchase its high-value exports. As policymakers work to integrate more variable renewable energy (VRE), and as corporates and developers adapt their strategies in anticipation of forthcoming Greenhouse Gas Protocol (GHGP) accounting updates, two key questions emerge: what is 24/7 CFE, and what does it cost?

24/7 CFE means matching every hour of electricity use with electricity from carbon-free sources. It ensures clean power is actually available when it is needed, all day, every day, instead of buying annual clean energy certificates. This approach is especially important for heavy industry and cloud computing, whose electricity demand is typically flat around the clock, making it essential for their long-term decarbonisation. This approach aligns the interests of large-scale consumers with those of grid planners, who must balance electricity demand in real time while expanding the grid at the lowest possible cost. Shifting to this approach is a central focus of the GHGP, which governs how companies account for emissions from purchased electricity, and is in the process of a multi-year revision of its standards. However, while hourly emissions accounting is emerging as the preferred accounting method, the GHGP does not set targets or grade performance.

Our analysis indicates that planning for 24/7 CFE procurement offers a no-regrets option for Taiwan's energy planners, grid operators, and corporates. By adopting a diversified technology portfolio, corporates can address land constraints and achieve 80% hourly CFE matching at a unit cost lower than the lowest average electricity tariff recorded over the past six years. This approach would cut emissions by nearly 75% and generate nearly US$1 billion in annual fuel savings for Taiwan's power system. Moreover, as these historical tariffs are heavily subsidised, PPA-based CFE becomes even more competitive when compared with the true cost of generation.

A diverse technological mix is essential to mitigate the risks of pursuing high CFE scores under strict additionality criteria. Even in optimistic scenarios, the potential for adding solar and onshore wind in Taiwan is limited. The technologies that have recently attracted government interest each come with distinct challenges. Geothermal, while appealing for its high capacity factor, has been slow to scale. In its absence, offshore wind carries a disproportionate share of the CFE burden, despite being non-dispatchable and subject to seasonal variability. Finally, adding innovative thermal technologies, such as carbon capture and storage or hydrogen co-firing, may ease investment pressures; however, their actual CFE delivered per dollar invested remains largely untested.

There is truly no silver bullet for Taiwan, which is why we advise further careful exploration of the fullest possible palette of technologies. We hope this initial analysis helps Taiwan's energy planners and market participants better understand the challenges and opportunities associated with 24/7 CFE and supports the Taiwanese government's 2030 and 2050 decarbonisation ambitions.

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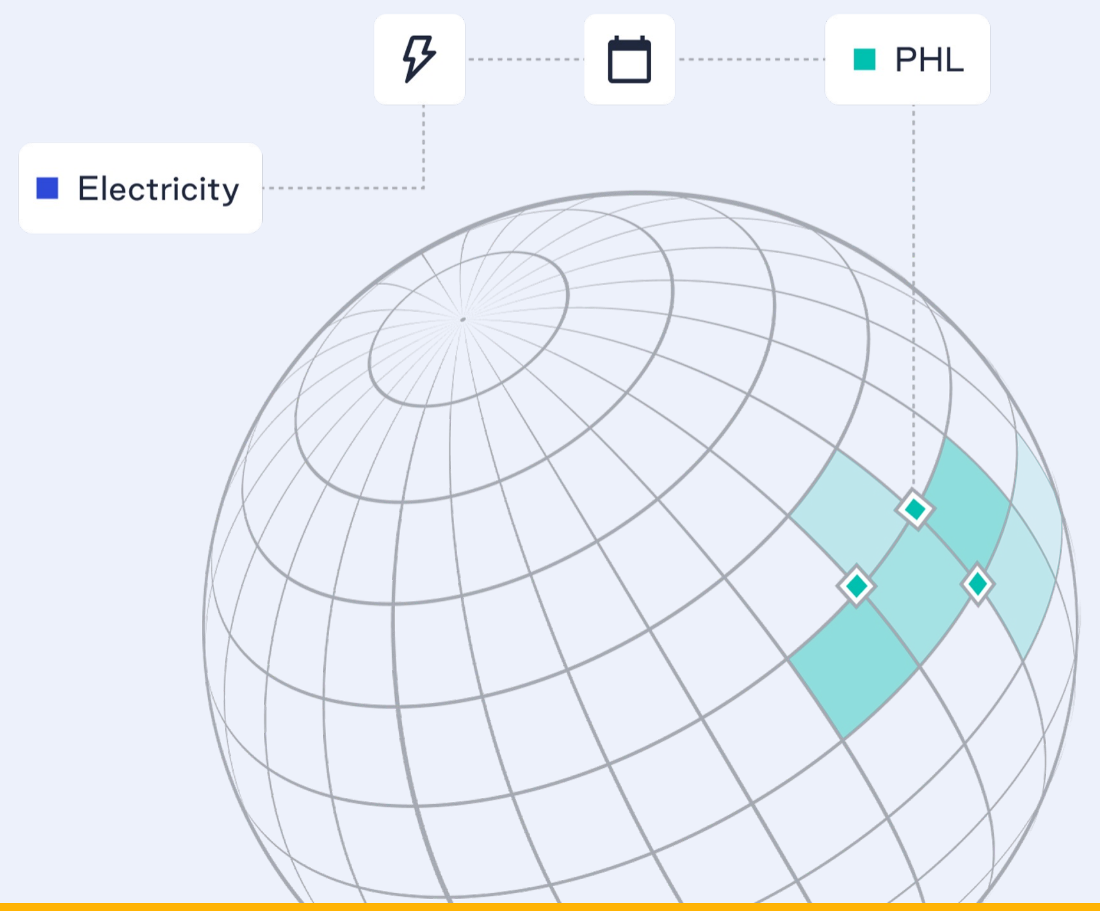

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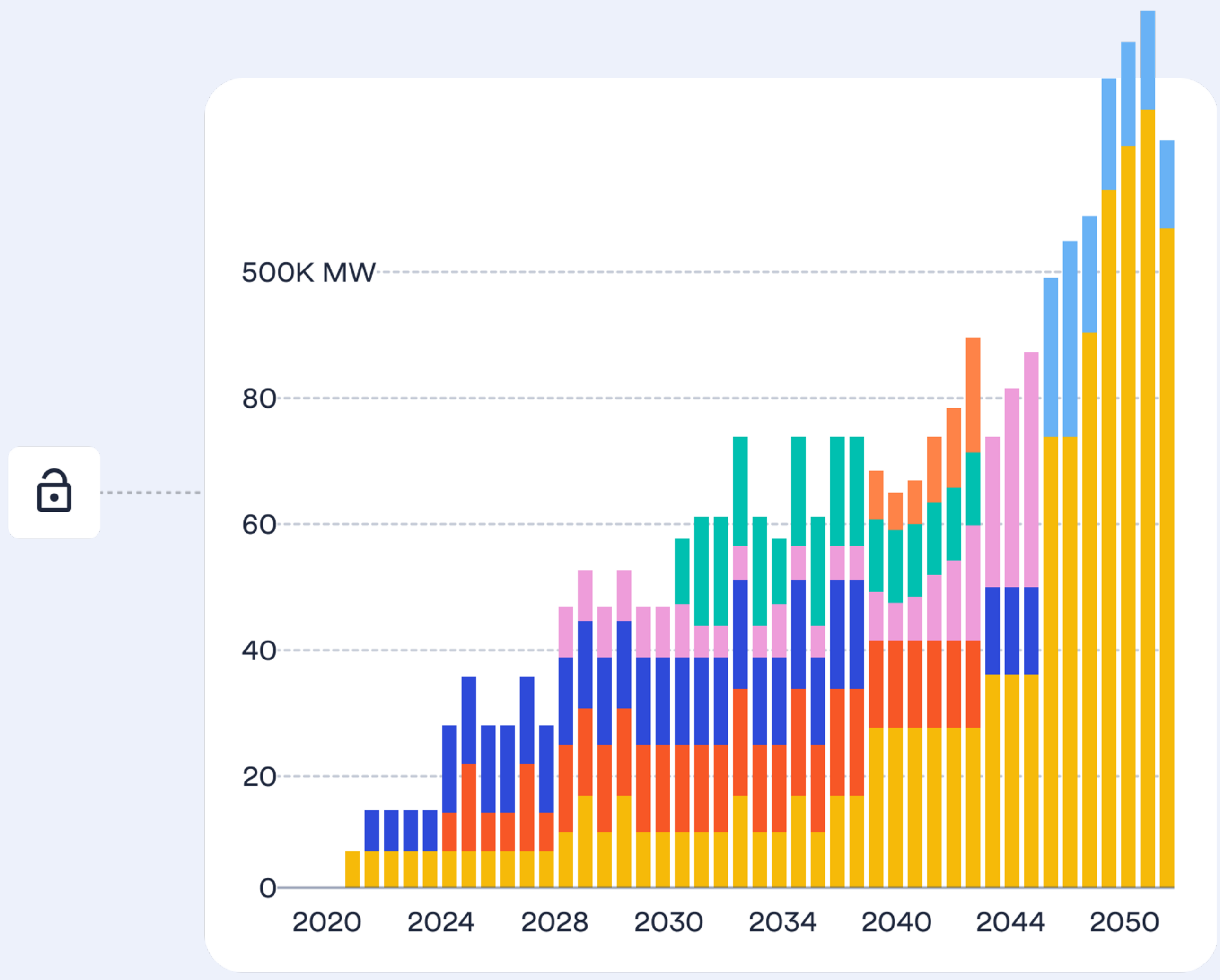

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Funded by SEQUOIA CLIMATE FOUNDATION, Google.org, Bloomberg Philanthropies, Quadrature Climate Foundation

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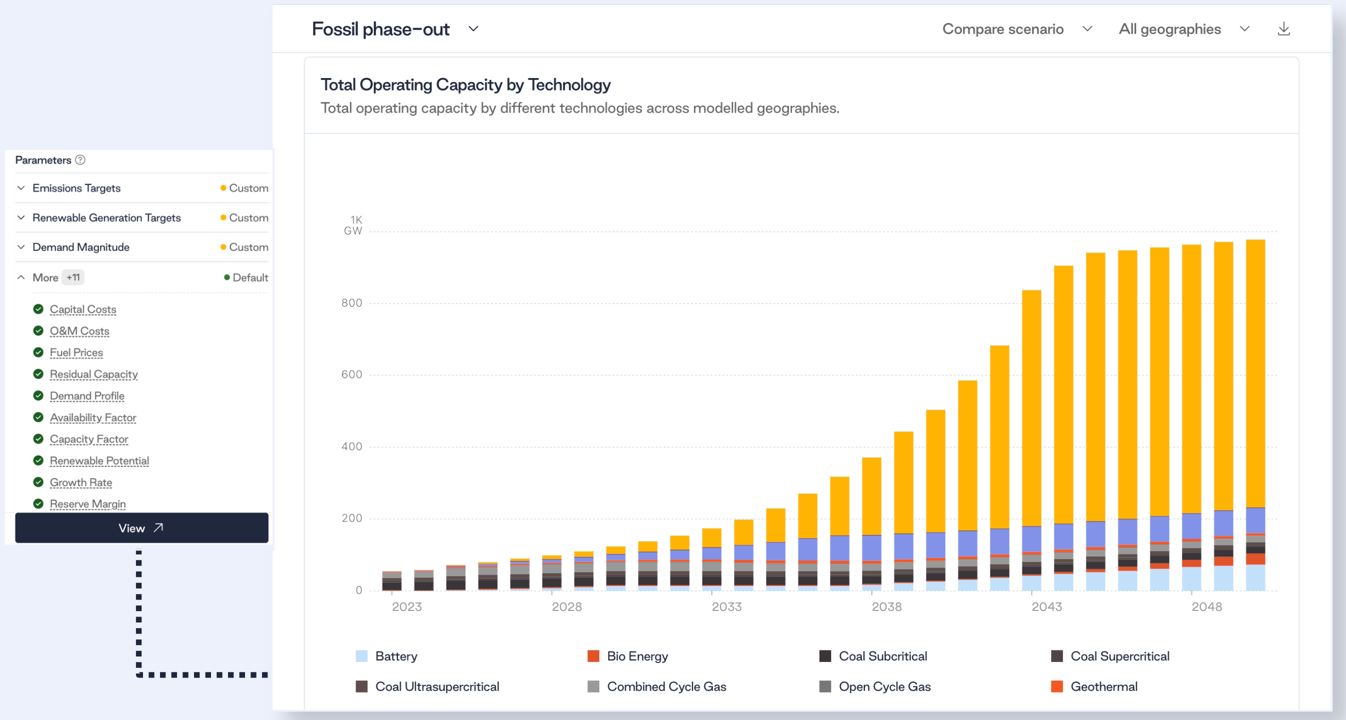
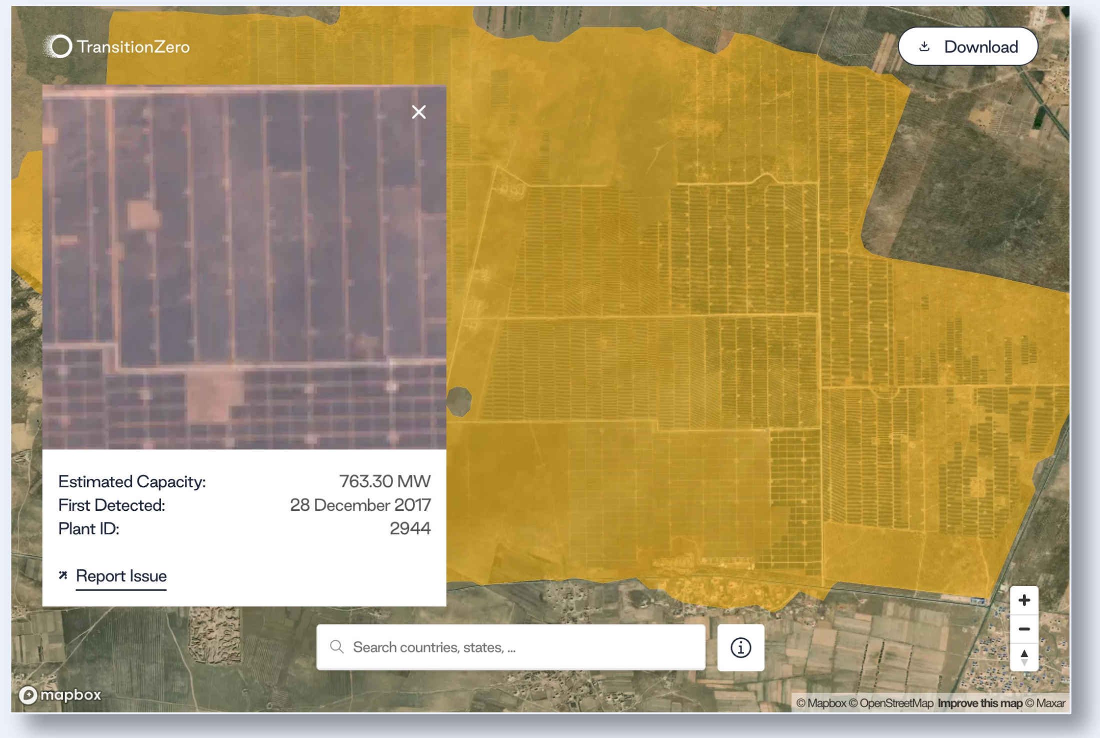
TZ-SB is free, no-code modelling platform that allows analysts working on energy transition planning to build, run, and analyse results from electricity system models – quickly, transparently, and at scale.



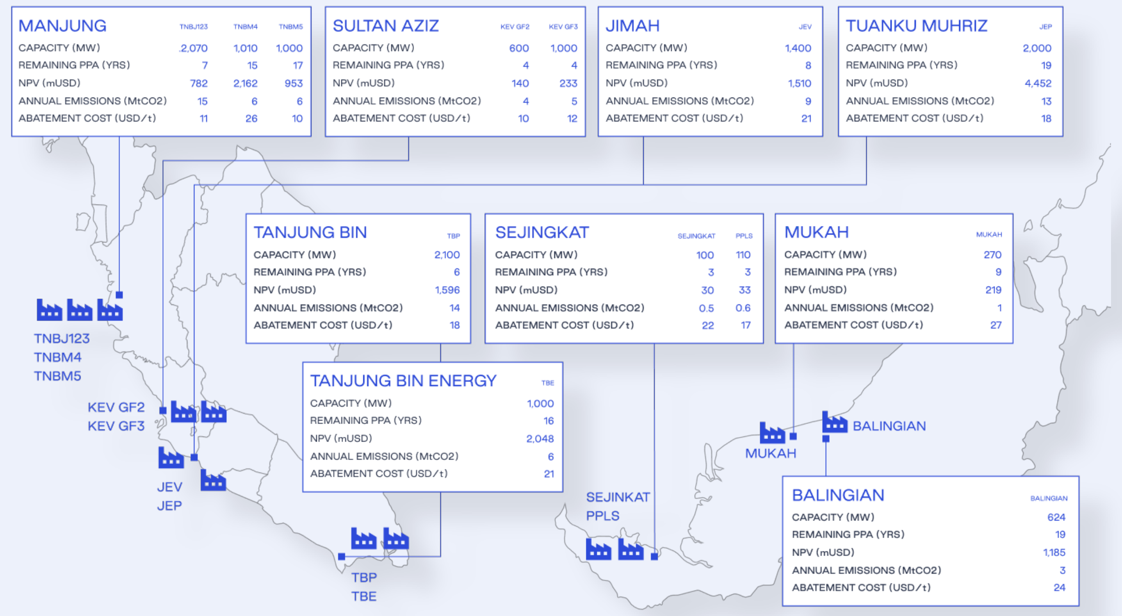
Solar Asset Mapper

TZ-SAM is an open access dataset of solar facilities, powered by machine learning and geospatial data. Tracks 100,00 solar assets across 200 countries, with ~100 GW of capacity added each quarter.



Coal Asset Transition Tool

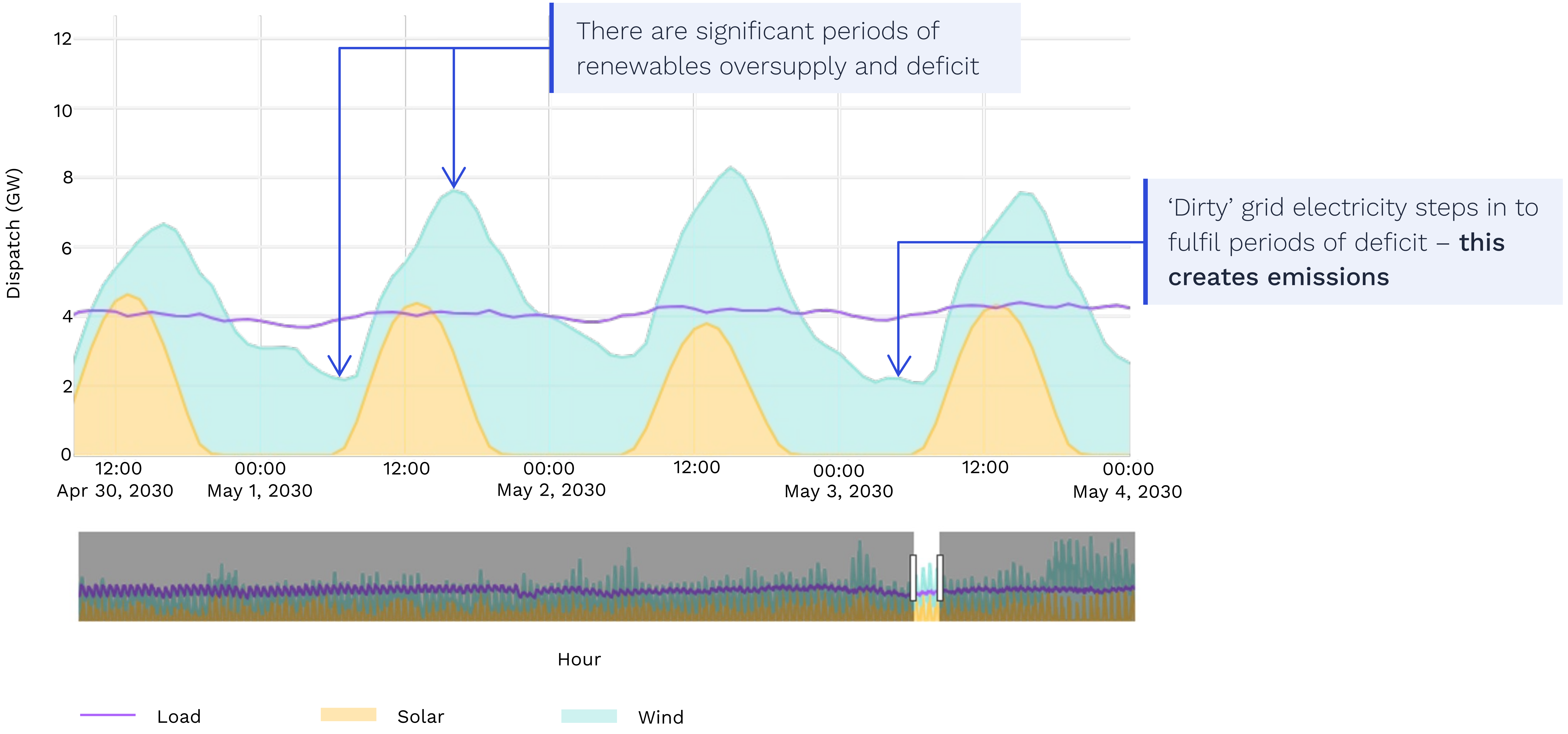
TZ-CAT is an open data product that supports the refinancing and replacement of coal plants in an affordable, just way. TZ-CAT is currently available for the Philippines, Indonesia, and Malaysia.



Background to Carbon Free Electricity (CFE)

Power consumers are grappling with mismatches between the generation and consumption patterns of clean electricity

What does an annual matching regime look like?

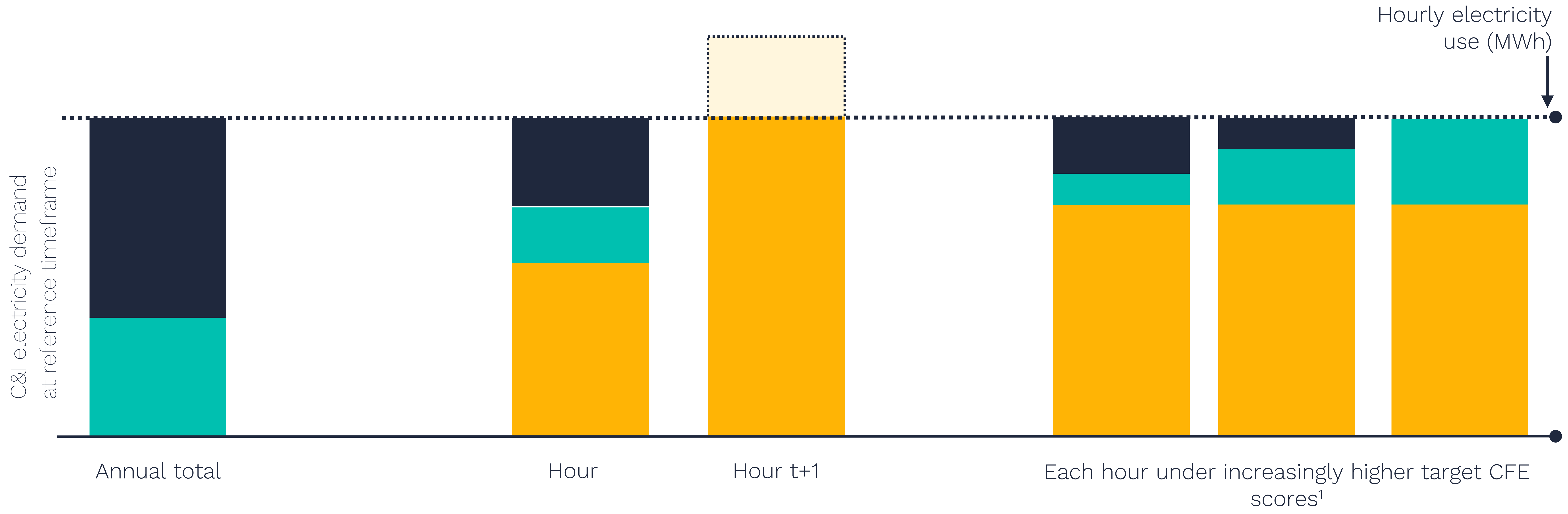


Key points

- Commercial and industrial (C&I) consumers face pressures to reduce their consumption of polluting electricity.
- Reliance on 100% renewables PPAs result in cycles of oversupply and deficit, where only some hours truly benefit from CFE.
- Frequently the rest of the system, featuring generally higher emissions, has to step in during periods of deficit.
- Matching consumption to generation hour by hour ("24/7 CFE") seeks to maximise CFE reliance round the clock.

Shifting guidance on emissions reporting

The GHG Accounting Protocol is evolving, and may require companies to report Scope 2 emissions based on hourly accounting



Situation 1:
Do nothing

C&I consumer's electricity consumption is met only by the regional grid, which is for the most part carbon-based.

Situation 2:
Annual matching (current common practice)

C&I consumer's electricity consumption is only partially matched, resulting in either a shortfall or an oversupply of CFE.

Situation 3:
24/7 CFE

Electricity use is fully matched with CFE. We can use a blended approach, in which some of the demand is matched by a PPA, while the remainder can be imported from the grid, provided it meets CFE threshold.

Key points

- A consumer's CFE score is the average of Situation 3 across all hours of the year.
- Principles that CFE should meet are to be locally sourced (from the same grid zone), time-matched (ideally hour by hour), and resulting from additional investments.
- CFE includes, by definition, a commitment to technological neutrality.

Carbon-based grid supply
CFE from grid supply
CFE PPA consumed
Excess CFE PPA (not counted towards CFE score)

[1] Note that at 100% CFE C&I consumers can rely on the grid only if the grid itself is also 100% CFE. A grid that features emitting generators can also be relied upon if the consumers seek to reach a lower CFE score.

How is Carbon Free Electricity measured?

The CFE score includes PPA-procured generation, and the cleanliness of the wider grid

- The CFE Score is a percentage score which measures the degree to which each hour of electricity consumption is matched with carbon-free electricity generation. We follow the methodology set out by Google[1].
- This is calculated using both carbon free electricity provided by through PPA contracts, as well as CFE coming from the overall grid mix. It is calculated as:

$$\text{CFE Score \% }(h) = \frac{\text{Contracted CFE MWh} + \text{Consumed Grid CFE MWh}}{\text{C\&I Load MWh}}$$

where:

$$\text{Contracted CFE MWh} = \text{Min (C\&I Load MWh, CFE Generation MWh)}$$

$$\text{Consumed Grid CFE MWh} = [\text{C\&I Load MWh} - \text{Contracted CFE MWh}] \times \text{Grid CFE \%}$$

- The Grid CFE % is calculated by looking at the what percentage of the generation comes from carbon free sources.
- The contracted CFE score is capped at 100%, even if there is excess CFE that is exported back to the grid.

An example calculation

Participating C&I load =	*100 MWh*
Contracted CFE generation =	*65 MWh*
Grid Imports	*100 - 65 = 35 MWh*
Grid CFE	*45%*
CFE Score =	*[65 + (35 x 0.45)] ÷ 100 = 81%*

Here, the participating C&I consumer has a load of 100 MWh which is participating in CFE/round-the-clock matching.

In this example hour, they have procured 65 MWh of clean generation through PPAs (e.g. some combination of solar and batteries) and must import the remaining 35 MWh from the grid to meet the load.

The grid at that hour has a CFE score of 45% (i.e. only 45% of generation is from CFE sources). This results in an overall CFE score for the C&I consumer of 81% in that hour.

[1] Google 2021, "24/7 Carbon-Free Energy: Methodologies and Metrics"

Key questions

Stakeholders need to better understand the implications of this shift

What are the implications in markets with high levels of fossil generation when a significant share of C&I consumers shift from annual to hourly matching?

What are the costs and benefits of hourly matching at the system level, i.e. the Taiwanese power sector and the actors involved in generation, storage, transmission, and distribution?

What other implications of hourly matching are there for both the wider system and C&I consumers?

To what extent are nascent technologies (storage or innovative thermal generation) needed for higher shares of hourly matched CFE?

To what extent can a wider palette of CFE technologies affect system-wide costs and benefits?

Technology palettes

We explore how additionality and technological choice affect system costs and benefits arising from greenfield investments

Technology	Palette 1	Palette 2	Palette 3
Onshore wind, solar, offshore wind, geothermal	✓	✓	✓
Battery storage	✓	✓	✓
Long-duration energy storage[1]	✗	✓	✓
Gas with CCS	✗	✗	✓
H_2/NH_3 co-firing[2,3]	✗	✗	✓

1 Liquid air storage.
2 For H_2/NH_3 only generation from the non-fossil share is accounted as CFE(10% and 20% respectively). For CCS we consider a 70% CO_2 capture rate, with the remaining 30% of unabated generation not accounted for as CFE.
3 For Taiwan, we exclude NH_3-coal cofiring and only allow H_2-gas cofiring to be considered in Palette 3 to align with Taiwanese government's policy ambition of phasing out coal.

Wider technical scope should lower system costs

- The "brownfield" capacity mix in our Reference Scenario will include CFE sources of low additionality (pre-existing hydro, renewables plants, as well as pumped and battery storage) and CFE plants likely to be built under business as usual conditions – all of which will contribute to the CFE score of the local grid
- Palette 3 also considers the non-conventional parts of innovative thermal plants[3] as additional

Overview of the Taiwanese power sector [1]

Generation and capacity mix as of 2024 (TWh, GW)

67 GW
Total nationwide capacity

289 TWh
Total nationwide generation

83%
Unabated thermal generation share

12%
Renewables generation share

3.1 GW
Renewable capacity added in 2024

Source: MOEA E-STAT (2024) including captive power plants
[1] Other includes pumped hydro, geothermal, biomass and waste

Overview of the Taiwanese power sector [2]

A brief look into real-world and modelled CFE procurement strategies

C&I consumers currently have four procurement options for carbon-free electricity (CFE) in the Taiwanese electricity market, all of them involving Taiwan Renewable Energy Certificates (T-REC). T-RECs are the vehicle for trading environmental attributes of electricity, with the government issuing T-RECs to generators, who can then gain revenue when consumers interested in renewable electricity eventually buy some form of certified electricity. The four options are::

1. **On-site generation:** Involves investing in CFE capacity at the consumer's premises, with T-RECs self-claimed and retired by the consumer.
2. **Direct offsite PPAs:** Consumers contract directly with CFE generators, with power delivered through dedicated lines or wheeling. Generation and consumption are tracked, and T-RECs are issued and retired in real time..
3. **Unbundled T-REC purchase:** Consumers buy T-RECs separately from their electricity, usually from entities with surplus generation. Transactions occur bilaterally or on the official T-REC market.
4. **Through retailers:** Licensed retailers buy CFE with bundled T-RECs and sell it to consumers, handling all tracking and matching on their behalf.

Unlike many markets, Taiwan's T-REC system uses a 15-minute matching mechanism. In each interval, CFE generation and consumption are compared, and the certifiable CFE is the minimum of the two. Monthly claims are the sum of all matched intervals. This strict sub-hourly matching improves accuracy but can create inefficiencies when excess generation or deficits cannot be reallocated in real time. To address this, a second-stage monthly balancing mechanism allows partial reallocation of unmatched generation, adding flexibility while preserving temporal integrity.

T-REC's two-stage allocation mechanism reflects our study's core principle that CFE generation and consumption must be time-aligned, though there are key differences between the two systems:

1. **Temporal granularity and evaluation metric:** T-REC enforces 15-minute matching, whereas hourly matching operates on a looser, hourly basis and relies on timely issuance of time-stamped certificates to produce a continuous matching score.
2. **Technology scope:** Hourly matching includes a broader range of CFE sources and storage technologies, such as nuclear, CCS, cofiring plants and batteries. In contrast T-RECs are limited strictly to renewables and do not recognise directly the time-shifted generation of battery even if charged with renewables.
3. **Handling of excess generation:** In practice, surplus renewable generation is procured by utilities at a fixed FiT or pre-agreed price, while our model assumes settlement at the marginal cost of the displaced generator.

Selected moments in Taiwan's renewable procurement journey

2017 — T-REC created
Electricity Act is amended to enable the creation of T-RECs and renewable energy retail market

2020 — Trading initiated
First renewable energy trade through the T-REC system occurs, allowing multiple procurement routes

2022 — Matching flexed
Regulatory revision upgrades its initial 15-minute matching into current more flexible two-step allocation structure

2025 — Granularity mismatch
Ongoing discussions highlight the gap between 15-minute generation data and monthly certificate issuance, prompting moves toward stricter sub-hourly matching and market-based trading of surplus energy

Executive summary

Key takeaways from our CFE modelling in Taiwan

An overview of our study approach

How we modelled carbon free electricity in Taiwan in 2030

We developed a representative 2030 grid and created a dispatch model with hourly granularity to model the Taiwanese island as one single node. We tested different clean electricity policies to see the impact of these interventions on costs, emissions and other key system metrics. **Our step-by-step process is as follows:**

01

We model the Taiwanese grid as one single node and assign 5% of the total grid demand to C&I consumers participating in clean electricity matching. This 5% is representative of general C&I demand moving towards decarbonisation.

02

This 5% of demand is modelled as following either an annual matching or an hourly matching scheme (testing between 70-100% hourly CFE). C&I consumers procure PPAs from additional clean generators to supply this clean electricity, which are built and optimised by our model.

03

We assess the nationwide impact of these schemes for both the C&I consumer as well as the wider Taiwanese power sector.

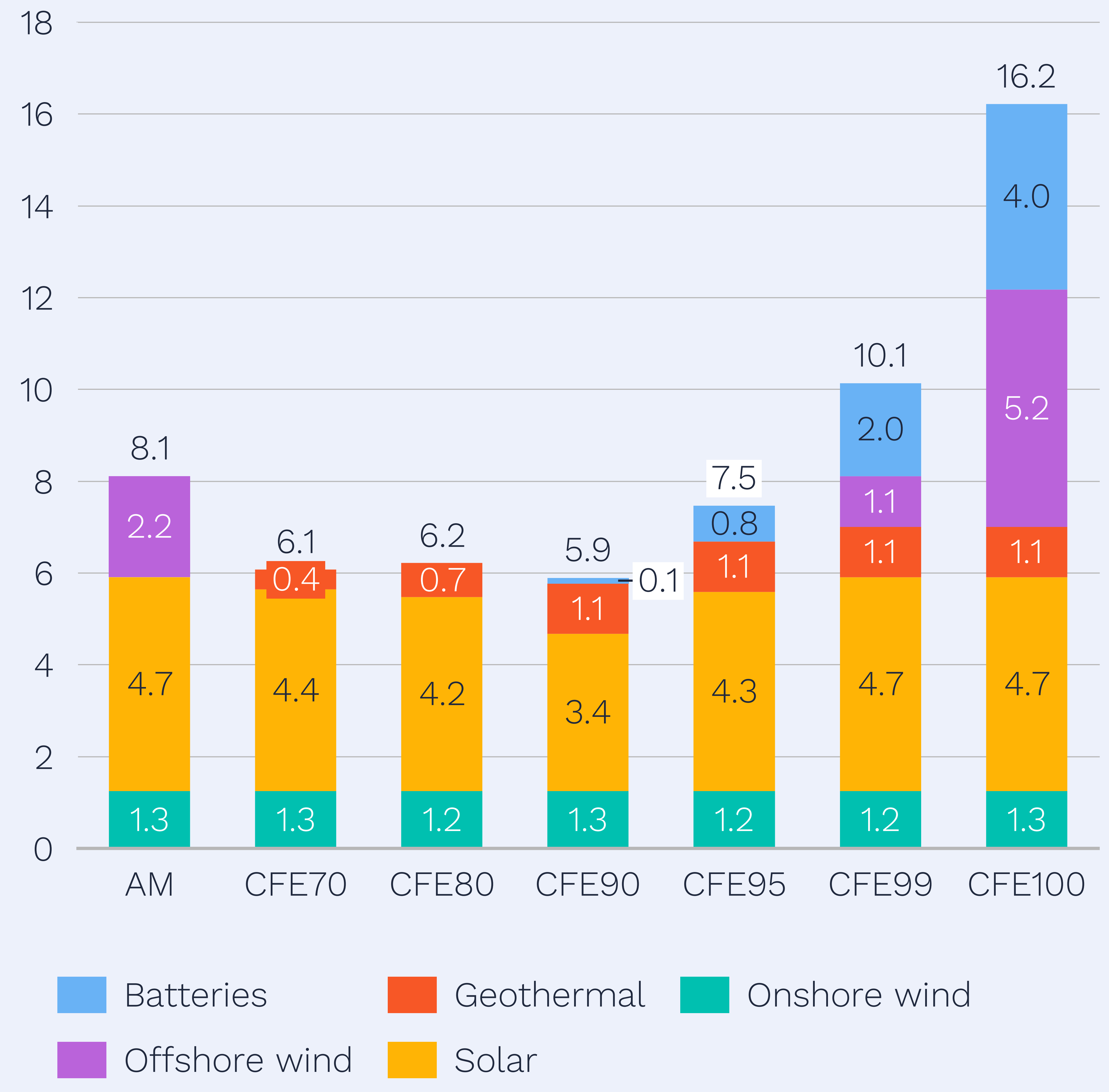
Solar, onshore wind and geothermal can deliver CFE 80

Batteries and offshore wind come into play under more stringent scenarios

1. **A diversified technology mix is essential.** Meeting either annual or hourly matching goals requires tapping at least three renewable technologies. Without expanding into new technologies like geothermal and offshore wind, the model becomes infeasible as it is unable to overcome renewable constraints on onshore wind and solar, which are limited by land scarcity. In Taiwan, onshore wind reaches its maximum build limits across all scenarios, making it the foundation of the mix. Beyond that, the order of deployment considers both cost competitiveness and supply reliability.
2. **Geothermal is the preferred option over offshore wind for hourly matching.** Although levelised cost of energy (LCoE) analysis suggests offshore wind (US$128/MWh) is cheaper than geothermal (US$133/MWh), the model favours geothermal under hourly matching. Geothermal is so attractive that between CFE 70 to CFE 95, that solar capacity, the second cheapest technology after onshore wind by LCoE, falls below levels seen under annual matching, while offshore wind only appears in CFE99 once the geothermal potential has been exhausted. Offshore wind in Taiwan faces strong seasonal variability, especially in summer when electricity demand peaks, making it less reliable for round-the-clock supply. Geothermal, by contrast, provides round-the-clock power and better alignment with evening demand, making it more suitable at hourly matching where electricity procurement from the grid is increasingly restricted.
3. **From CFE 70 through to CFE 95, the system requires lesser new renewables capacity than under annual matching.** Annual matching first exhausts onshore wind (1.3 GW) and solar (4.7 GW) due to their low LCoE, then turns to offshore wind (2.2 GW), whose seasonality is irrelevant in this framework. Offshore wind capacity is sized to meet residual demand after solar and onshore wind, before investing in batteries. Batteries (124 MW) appear from CFE 90 onward and, together with geothermal, provide sufficient firming to keep total capacity below the annual matching level (8.1 GW), reaching only 7.5 GW at CFE 95.
4. **System-wide capacity requirements increases exponentially going beyond CFE 80.** While moving from CFE 70 to CFE 95 requires just 1.4 GW additional capacity, the final push from CFE 95 to CFE 100 requires an additional 8.7 GW – all of which is concentrated in strongly seasonal offshore wind and firming batteries..

Buildout by 2030 (GW)

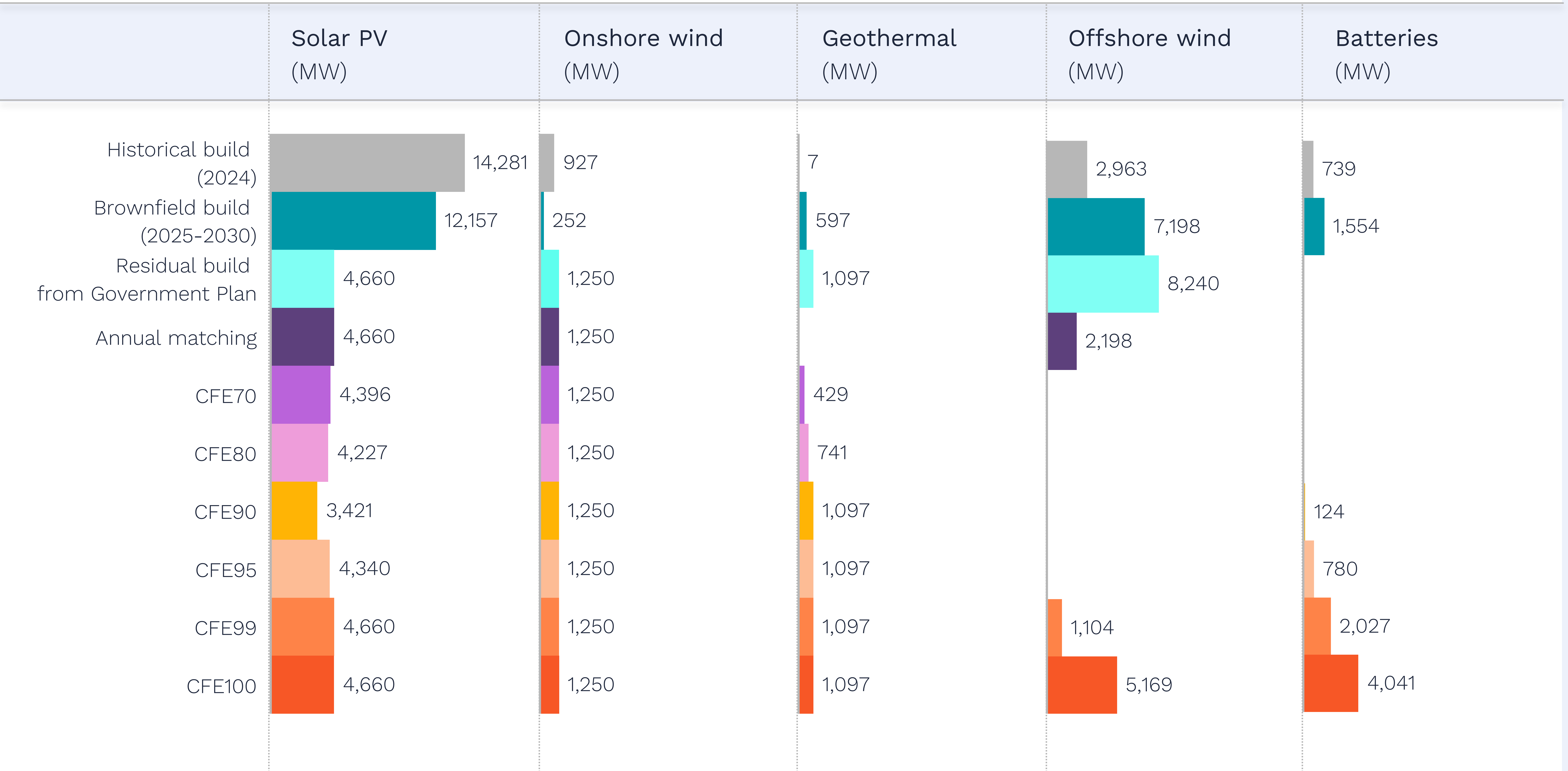
Generation & storage requirements rise along with stringency



Source: TZ modelling.

Strain under Tech Palette 1

Achieving CFE 80 with hourly matching is within reach, but it requires C&I consumers to maximise land-limited renewables while also drawing on the broader potential of geothermal



Notes

- The brownfield build includes expected renewable capacity expansion based on government 2030 targets, adjusted for historical build rates. The greenfield build allows additional capacity only up to the residual potential identified in the government's 2035 projection.
- Onshore wind reach its limit across all scenarios while solar requires at least 75% of its residual build in all scenarios. For onshore wind, this means more than doubling Taiwan's projected capacity of 1.2 GW by 2030 and tapping all available secondary sites, consistent with the Taiwan 2050 Calculator Level 4 pathway. For solar, this implies accelerating the 2035 utility-scale solar target of 12 GW by 5 years.
- Geothermal maxes out by CFE 90, while offshore wind is not needed at all at below CFE 99 scores – other than annual matching where its seasonality does not matter. It still leaves about 3.1 GW of potential untapped even at CFE 100.
- Storage is only needed from CFE 90 onwards but grow steeply towards full decarbonisation. By CFE 99, storage capacity must grow 1.9-fold relative to the 2030 brownfield projection. Reaching CFE 100 requires a 2.8-fold increase.
- Hourly matching at CFE 80 is achievable for C&I consumers, with about 6.2 GW of additional generation and storage. This comes from accelerating solar deployment by 5 years, utilising all existing onshore wind secondary sites, and meeting geothermal ambitions by 2032 in full (a near 1.4 GW expansion up from just 7 MW today). Altogether, this represents slightly over one-fourth of Taiwan's projected 22 GW renewable expansion between 2025 and 2030.

Source: TZ modelling.

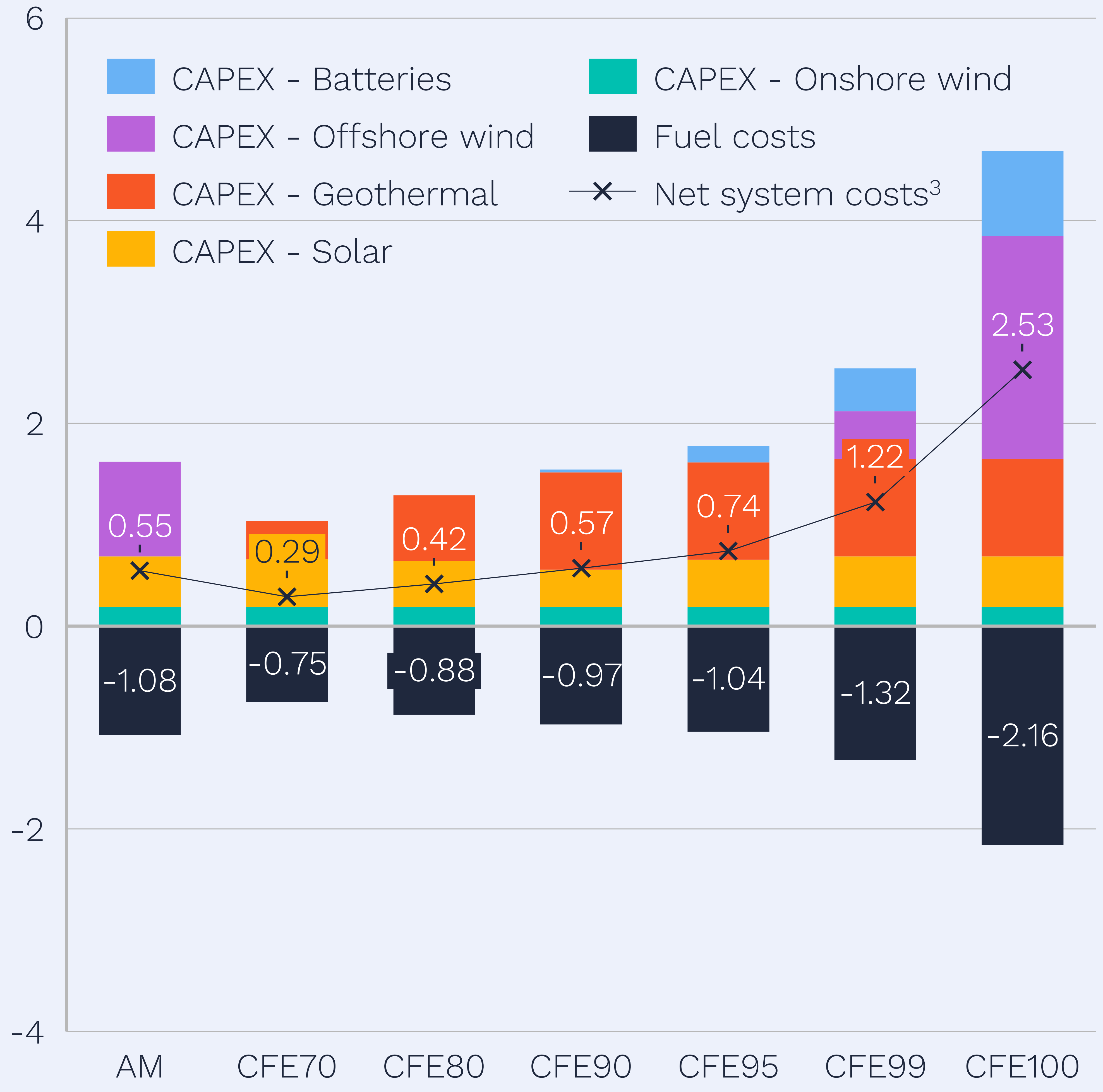
Hourly matching at CFE 80 saves nearly US$1 billion per year

Storage only becomes necessary beyond CFE 80, when C&I consumers can no longer rely on the grid

1. **Under our most basic technology palette, TP1, adopting CFE 80 hourly matching is cheaper than annual matching.** Compared to annual matching, CFE 80 hourly matching requires US$0.13 billion less net system investment. Compared to annual matching, CFE 80 hourly matching requires US$ 130 million less system investment. Although annual matching brings higher fuel savings (US$200 million more). As a result, net system costs under annual matching are 31% higher.
2. **Total system costs rise sharply when moving from CFE 80 to CFE 100, driven by the need for broader technology deployment**. At CFE 90, overall CAPEX is similar to annual matching (around US$1.6 billion), but investment shifts significantly: The US$940 million previously allocated to offshore wind moves entirely into geothermal, while part of the solar investment (around US$130 million) is redirected into geothermal and batteries. By CFE 99, the system must draw on all available technologies.
3. **Storage CAPEX rises exponentially under the highest CFE scores.** The CAPEX growth required for the extra storage alone when going from CFE 99 to CFE 100, is around US$420 million, which is the same as the original net system costs of reaching CFE 80.
4. **The final steps to full decarbonisation are materially more expensive.** Going from CFE 99 to CFE 100 more than doubles net system costs, from US$1.2 billion to US$2.5 billion, with an 84% rise in CAPEX. This surge is mainly due to a nearly fivefold increase in offshore wind investment from US$470 million to US$2.2 billion and a doubling of battery costs from US$420 million to US$840 million.
5. **Excess renewable generation consistently cuts fuel costs, delivering a key benefit across all CFE levels.** When PPA assets generate more than offtaker demand, the surplus can be sold back to the grid, displacing thermal generation. This drives substantial and growing savings for conventional generators ranging from about US$750 million at CFE 70 to US$2.2 billion at CFE 100. These fuel cost savings to the grid reduce overall system costs by as much as 46% at CFE 100.
6. **Fuel cost savings jump sharply in the move to full decarbonisation. Fuel cost savings increase by 64% when going from CFE 99 to CFE 100.** While the system oversizes offshore wind and battery capacity to provide enough CFE and time-shifting for the final low-renewable periods, it also produces large surpluses during other periods to be sold back to the grid, displacing thermal generation. This fundamentally reflects that the periods of low offshore wind generation are longer than batteries' operating window. The scale of this impact is likely heavily influenced by the weather year selected.

System-wide costs and benefits[1,2] under TP1

Costs/savings to the Taiwanese power sector in 2030 (billion US$)



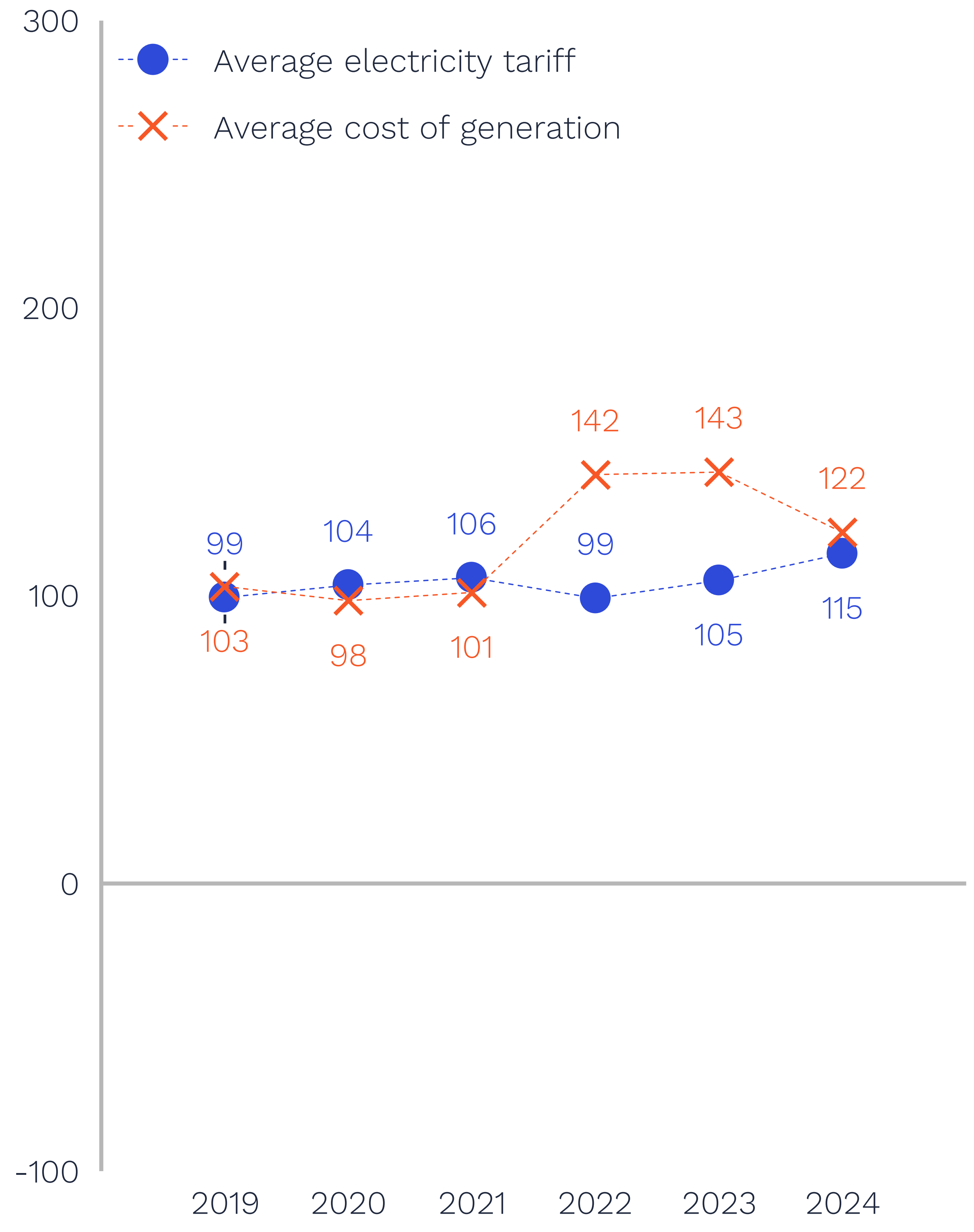
Source: TZ modelling.

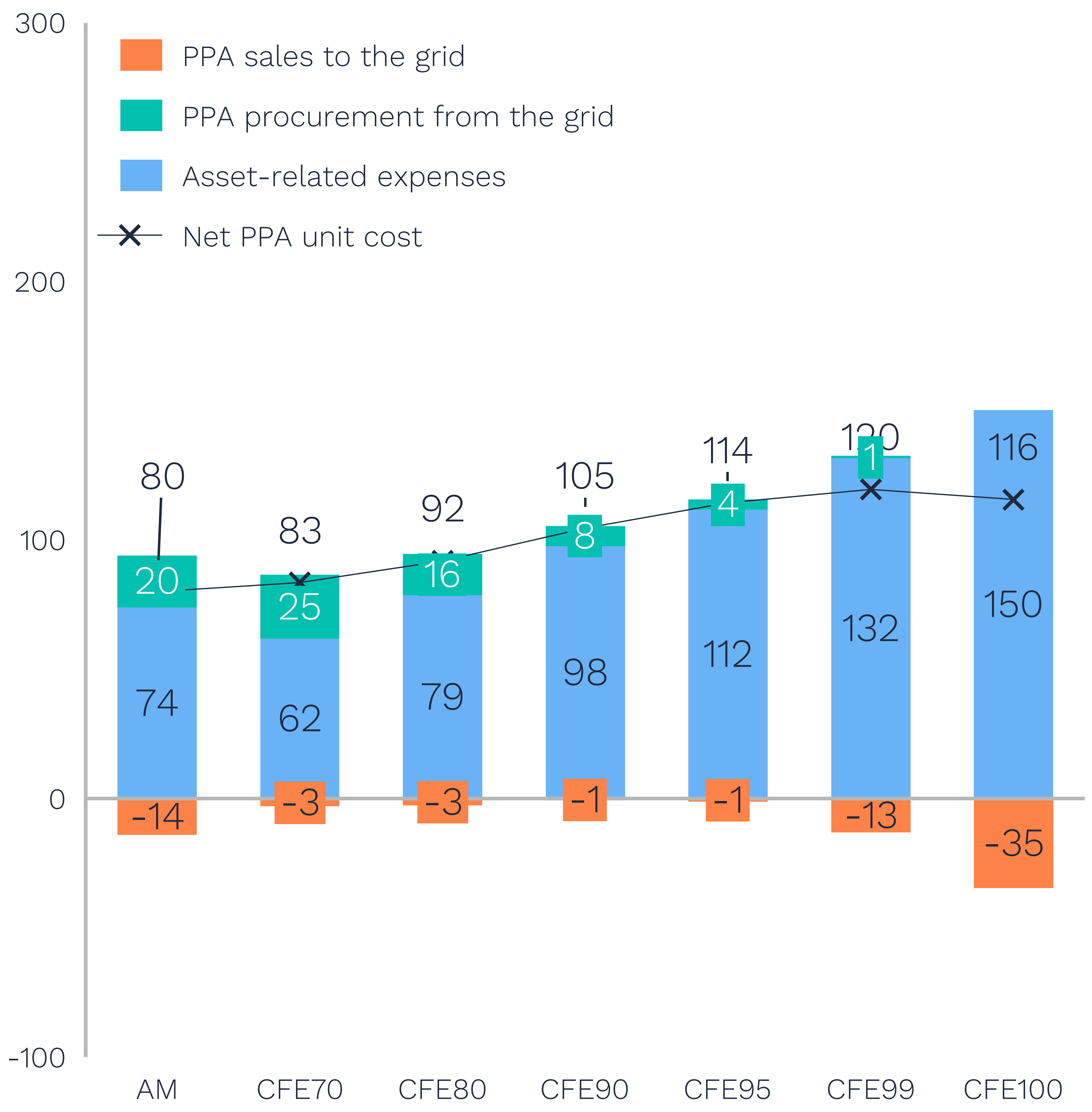
[1] These comprise all capital, operational, and fuel expenditure of the entire system, including PPA assets.
[2] CAPEX figures shown are expressed in real 2023 money base and annualised, based on the assumed lifetime of individual assets and discounted to present value.
[3] Net system costs are calculated from the sum of CAPEX paid by the C&I consumer and fuel cost savings to the grid.

Costs in context

The cost of CFE 80 is lower in real terms than the lowest observed average annual electricity tariff by Taipower since before the COVID pandemic

Historical average annual electricity tariff[1] against PPA unit costs (USD/MWh)





Notes

- At higher CFE scores, off-taker PPA unit costs increase far more slowly than total system costs. While total system costs surge by a factor of 6 between CFE 80 and CFE 100 (US$420 million versus US$2.5 billion), unit costs for C&I consumers rise by only a factor of 1.3 over the same range (US$92/MWh versus US$116/MWh).
- From CFE 70 to CFE 99, PPA sales under hourly matching are lower than or comparable to under annual matching. This is because annual matching, without the hourly constraint, allows more excess renewable power to be sold back to the grid. At CFE 100, however, the picture changes. The system must add 4 GW of offshore wind and 2 GW of batteries to decarbonise the final hours by time-shifting generation. This more than doubles surplus generation for grid sales compared to annual matching.
- Hourly matching reduces procurement from the grid. Under annual matching, procurement costs from the regular grid account for one-fourth of the unit cost (circa US$20/MWh) but gradually disappear with the transition to hourly matching regimes with progressively higher CFE scores.
- For CFE 70 to 80, the unit costs of both annual and hourly matching are lower than any historical annual average electricity tariff or generation cost recorded since 2019.
- Over the longer term, the 6-year average tariff of US$105/MWh aligns closely with our modelled PPA unit cost at CFE 90. Even at CFE 100, the modelled cost remains competitive with Taipower's 6-year average real generation cost (US$116/MWh vs US$118/MWh).

Source: MOEA, TZ modelling.

[1] All values were converted to USD using the average yearly exchange rate from the IMF and expressed in 2023 real money term..

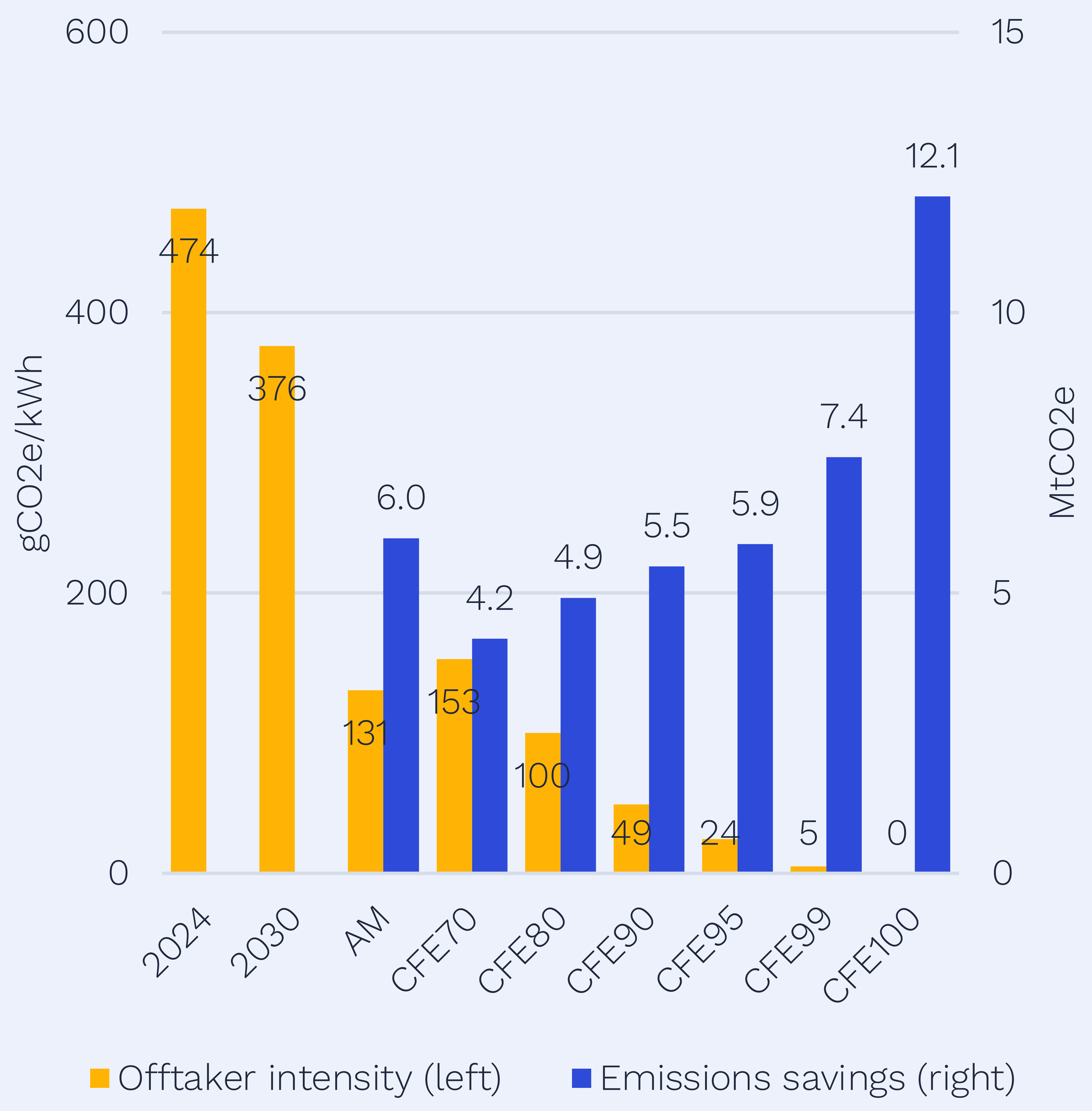
Hourly matching cuts emissions intensity faster

80% hourly matching can reduce C&I consumers' emissions intensity more effectively than annual matching

1. **System-wide emissions consistently fall as matching stringency increases.** Even under annual matching (131 gCO2e/kWh) C&I consumers can cut their emissions intensity by more than half compared to relying on grid supply (376 gCO2e/kWh). Additional system-wide gains continue linearly, before a sharp 80% jump in abatement at CFE 100. Notably, the final surge is largely driven by surplus CFE sold back to the grid, enabled by the much higher renewable capacity in the system. Meanwhile, offtakers' emissions intensity steadily declines across all CFE levels.
2. **The two most stringent hourly matching scenarios cut more system-wide emission than annual matching.** Annual matching achieves greater nationwide emissions reductions, because of the substantial sales of CFE from overbuilt assets back to the grid, and partly because CFE 70 through to CFE 99 the desired volume of CFE is lower than under the annual matching scenario. However, at CFE 99, hourly matching closes the gap and cuts 24% more emissions than under annual matching. By CFE 100, hourly matching delivers nearly 12 MtCO2e in emissions savings, almost double the 6 MtCO2e that annual matching achieves.
3. **Annual matching delivers lower emission intensity than CFE 70.** This is because annual matching, with its looser matching constraint, allows more renewables (8.1 GW at annual matching vs 6.1 GW at CFE 70) in the system, increasing CFE availability across the year. In contrast, CFE 70 relies more on fossil-backed grid procurements, causing its emission intensity to be higher than annual matching by 17% (153 gCO2e/kWh vs 131 gCO2e/kWh).
4. **Hourly matching at 80% decarbonises offtakers' emissions intensity more effectively than annual matching.** With 1.9 GW less capacity (6.2 GW for CFE 80 and 8.1 GW for annual matching) and US$0.13 billion less total system cost (US$0.42 billion for CFE 80 and US$0.55 billion for annual matching), CFE 80 delivers around 24% lower emissions intensity for offtakers despite delivering 18% lower nationwide emissions reductions. This advantage comes from greater reliance on geothermal in hourly matching, which provides reliable and dispatchable power, better aligned with demand patterns, unlike offshore wind that dominates annual matching. This highlights hourly matching's efficiency in reducing emissions per unit of electricity consumed.

Total abatement and emissions intensity for offtakers

Hourly matching beyond CFE 80 has stronger decarbonisation impacts for offtakers than under annual matching



Source: TZ modelling.

Technological neutrality reduces the buildout seen in TP1

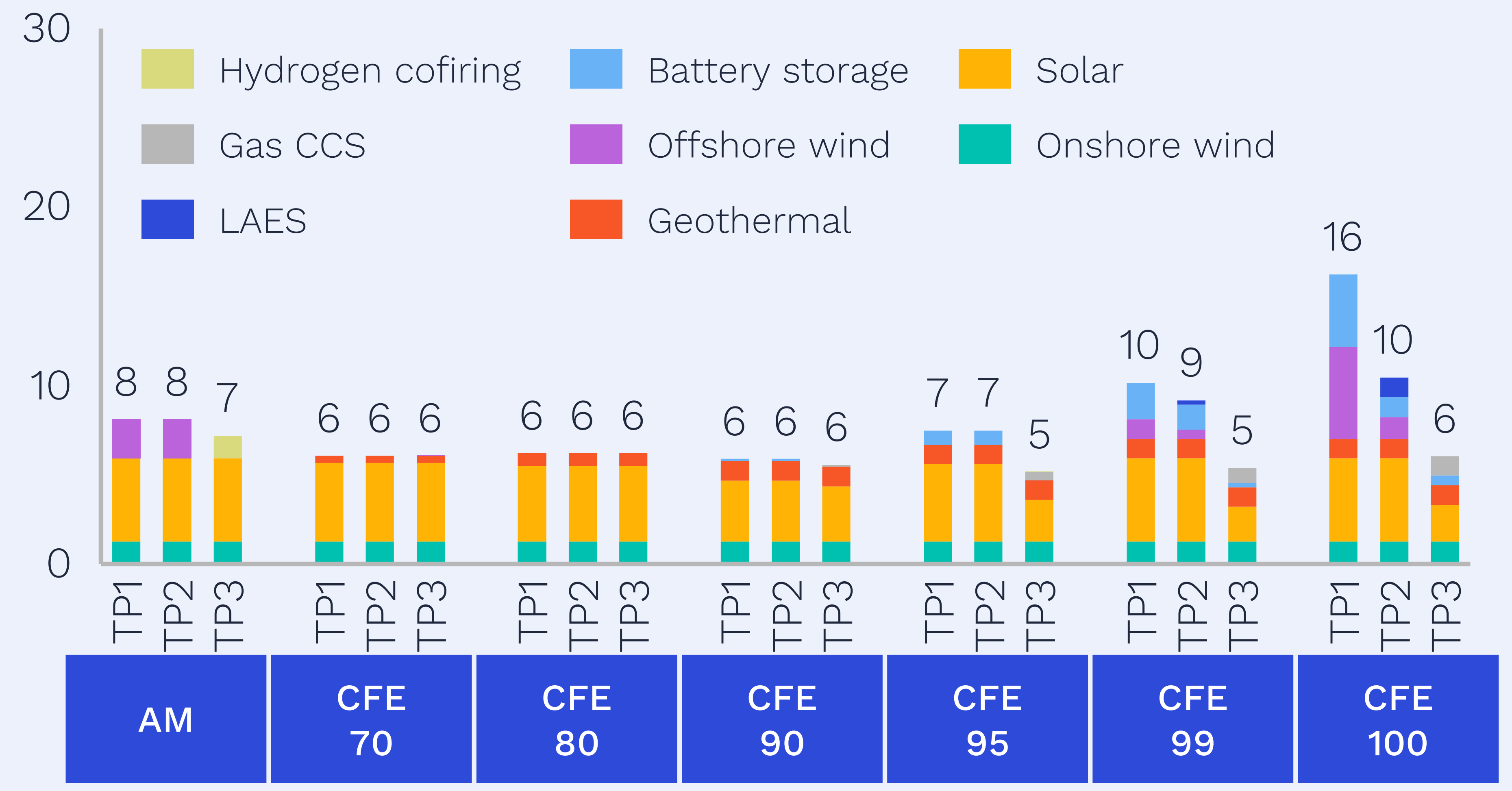
Emerging technologies can reduce build-out rates for renewables

1. **Adding liquid air energy storage (LAES) in Tech Palette 2 (TP2) cuts offshore wind requirements and significantly reduces battery capacity at CFE 100.** With a one-week storage duration—far longer than batteries' typical 6 hours—LAES can time-shift excess PPA generation to match demand. This lowers total generator buildout in TP1 by 32%, with offshore wind down 76% and batteries 45%.
2. **Gas CCS is the preferred innovative thermal technology for hourly matching.** In In Tech Palette 3 (TP3), we also assessed hydrogen co-firing, which the system favours under annual matching as the lowest-cost option at US$100/MWh – over offshore wind (US$128/MWh), geothermal (US$133/MWh) and CCS (US$129/MWh), which is consistent with LCoE analysis. Under hourly matching, however, CCS's higher CFE share (70% vs 10% for hydrogen co-firing) makes it more effective at meeting clean generation targets. CCS enters from CFE 90, increasingly displacing offshore wind, solar, and storage as CFE targets rise, while geothermal and onshore wind remain at their imposed build limits.
3. **Gas CCS eliminates the need of LAES and materially contracts the requirement for solar, offshore wind and batteries.** This is driven by its greater cost competitiveness as a dispatchable source compared to offshore wind or solar paired with storage. Beyond LCoE, its ability to cover renewable shortfalls over longer periods gives it an advantage over hybrid systems. However, CCS cannot fully displace offshore wind, which is cheaper, or geothermal, which delivers more CFE at similar capacity factors and lower cost.
4. **Introducing LAES in TP2 significantly reduces the emissions savings seen with TP2 at CFE 100.** With its longer storage duration, LAES absorbs surplus electricity that would otherwise be sold back to the brownfield and displace fossil generation, reducing overall emission cuts. It also lowers offshore wind capacity, further shrinking sell-back volumes and indirectly reducing emissions.
5. **Introducing CCS in TP3 results in lower national emissions than than other palettes.** The net impact is lower because offtakers are directly responsible for leaked emissions from the PPA CCS plants, and as a dispatchable generator CCS also significantly reduces the total volume of excess CFE that could otherwise be sold back to the regular grid for more emissions savings.

Source: TZ modelling.

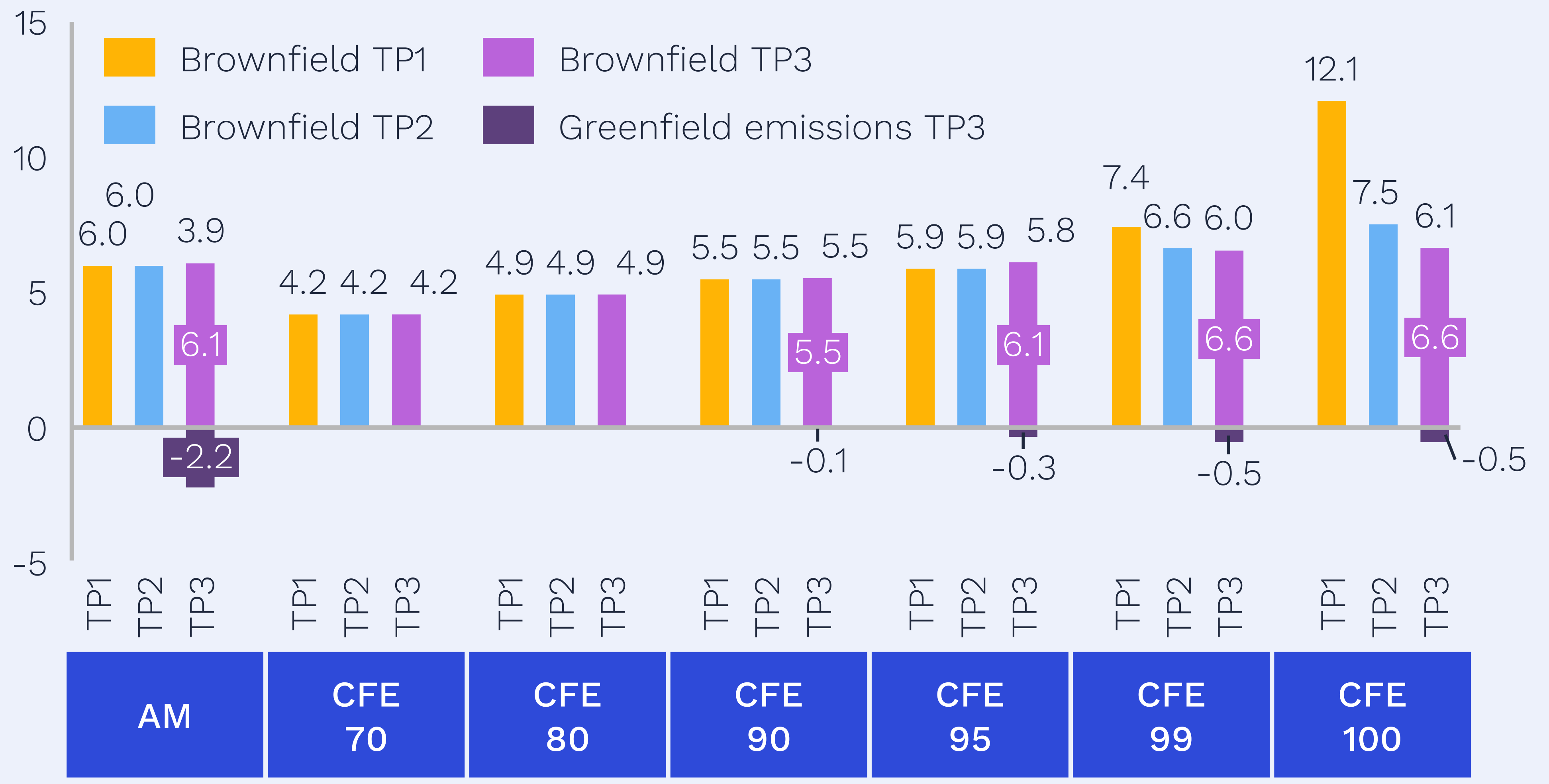
Buildout by 2030 (GW)

Dispatchable technologies reduce the need for overbuilding for low renewable output hours…



National emissions impact (MtCO2e)

…while still delivering emission cuts nationally

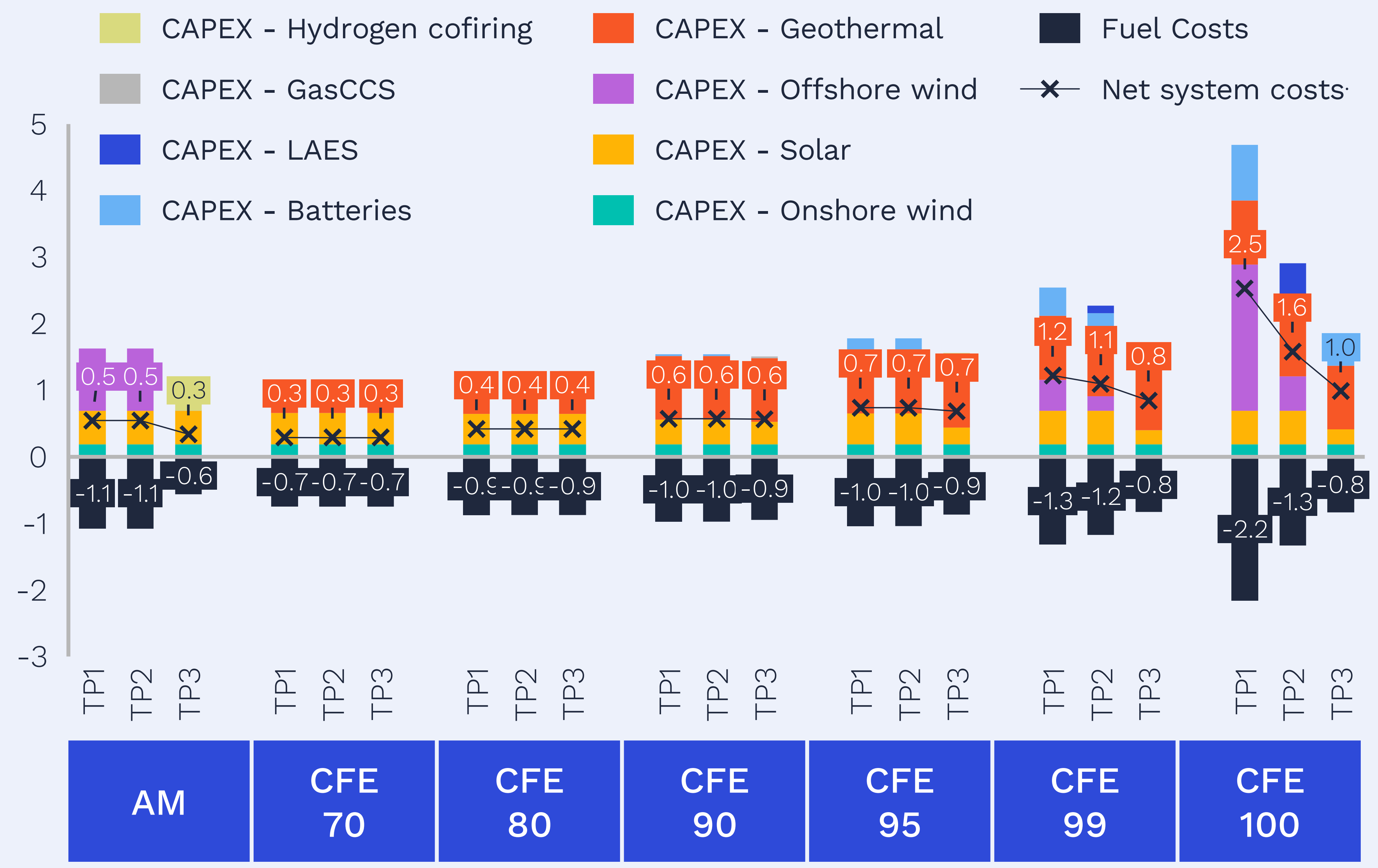


A wider choice of technologies lower system costs and ease renewable overbuild at high CFE levels

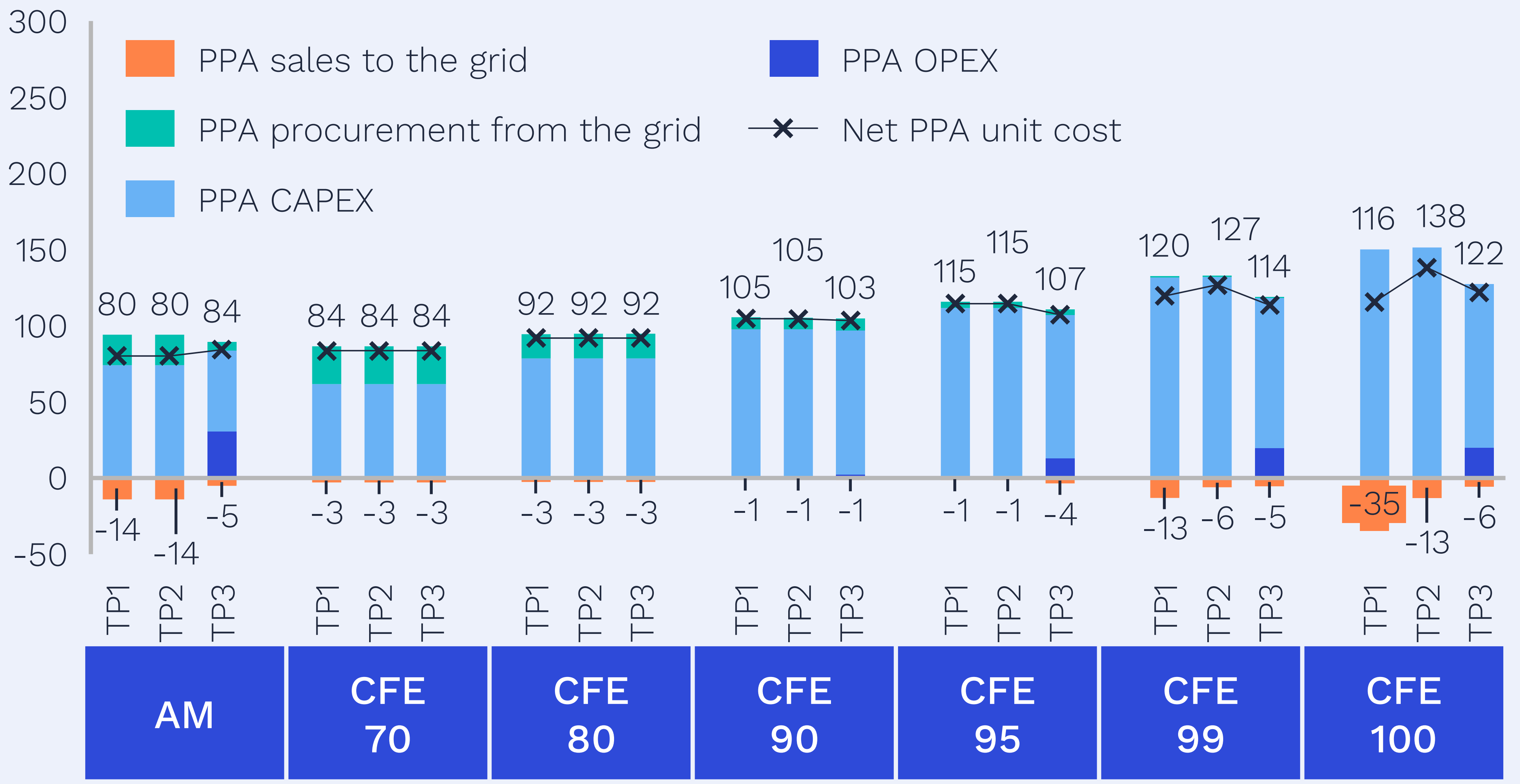
Dispatchable options reduce reliance on renewables and storage, curb cost escalation at CFE 100, and reshape the balance between system savings and PPA economics.

1. **System costs escalate much less at higher CFE scores.** At CFE 100, system-wide costs rise far less steeply when flexible technologies are included. Compared with TP1, costs fall by 38% in TP2 (with LAES) and by 61% in TP3 (with gas CCS). Capacity contraction is driven by two key factors, cost and dispatchability: offshore wind is reduced first (US$128/MWh), followed by solar (US$94/MWh), while dispatchable geothermal (US$133/MWh) and onshore wind (US$64/MWh – the cheapest option), continue to be fully utilised at their build limits. With less renewables, storage needs also decline.
2. **Fuel savings on the regular grid remain a very important component of system-wide savings.** Fuel cost savings on the regular grid are a key contributor to system-wide benefits. In TP3, however, these savings fall because flexible technologies reduce the volume of excess renewable generation to be sold back to the grid. In addition, CCS plants consume more gas than in the Reference Scenario, further reducing fuel savings.
3. **LAES raises PPA unit costs despite lowering system costs at the highest CFE level.** At CFE100, PPA unit cost in TP2 is about 19% higher than in TP1. This is driven by LAES's superior storage capability, which reduces the need for additional generation through better time-shifting, and by the extended discharge duration that allows more CFE to be stored for offtaker use rather than sold back to the grid.While this shift helps ease siting constraints and lowers system costs, it reduces revenues and ultimately raises net PPA costs.
4. **CCS lowers PPA unit costs by reducing overbuild pressure but also diminishes PPA sales.** In TP3, dispatchable gas CCS reduces slightly PPA unit costs between CFE 90 and CFE 99, though less than the system-wide cost savings it delivers. At CFE 100, however, TP3 becomes about 5% more expensive than TP1. While CCS avoids large renewable overbuilds thereby reducing required CAPEX and reliance on scarce land, this benefit is offset by lower PPA sales to the grid and higher fuel costs from operating the PPA thermal plants. Even so, TP3 remains cheaper than TP2, as dispatchable generation reduces the need for both renewable and storage build-out.

System-wide costs and benefits[1,2] (Billion USD)



PPA unit costs (USD/MWh)

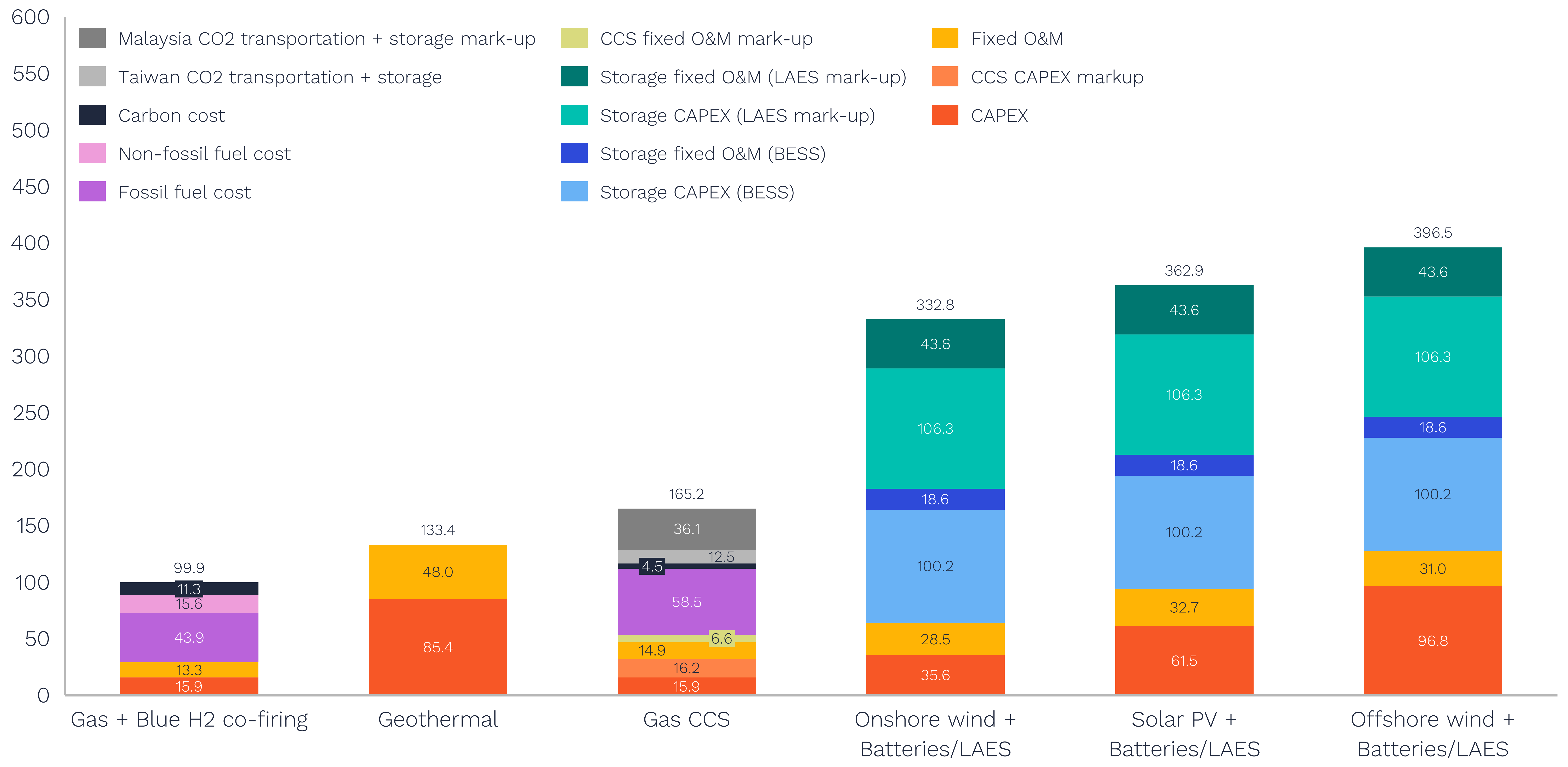


Source: TZ modelling.

[1] These comprise all capital, operational, and fuel expenditure of the entire system, including PPA assets.
[2] CAPEX figures shown are expressed in real 2023 money base and annualised, based on the assumed lifetime of individual assets and discounted to present value.
[3] Net system costs are calculated from the sum of CAPEX paid by the C&I consumer and fuel cost savings to the grid.

While widening the technological scope adds flexibility, the resulting capacity mix is sensitive to cost assumptions

LCOE by technology[1] (USD/MWh) – ordered from lowest to highest



Source: *TZ modelling.*

Notes

- At standard capacity factors[1], the ranking of levelised cost of electricity (LCoE) from lowest to highest amongst all technologies is in the following order: onshore wind, solar PV, hydrogen cofiring, offshore wind, gas CCS and lastly geothermal. However, adding storage to weather-dependent renewables making them hybrid plants immediately increase their LCoEs beyond those of innovative thermal technologies and geothermal. This explains why in TP3 the inclusion of innovative thermal reduces renewables capacity significantly.
- Our model findings show that gas CCS is so cost competitive that, even when transporting CO_2 out of Taiwan to Malaysia, it can still compete with hybrid renewable plants.
- Beyond LCoE, a key factor influencing technology uptake is the ability to meet greenfield demand at minimum cost. The model may prefer higher LCoE technologies that are freely dispatchable to cover lulls in renewable generation that cannot be cheaply covered by storage.
- An additional factor is a technology's ability to contribute to the target CFE score. For hydrogen co-firing, the non-CFE component raises its effective LCoE while not counting toward offtakers' CFE consumption, limiting its uptake.. Low sequestration rates for CCS negatively affect its competitiveness in the same manner.

[1] Maximum capacity factors of 66% inherited from our 2024 calibration for the thermal technologies, applied in our LCOE calculation also to gas CCS, and gas-hydrogen cofiring,. In addition, we have applied capacity factors of 13% for solar, 27% for onshore wind, 38% for offshore wind, specific to our weather year of choice, and maximum 75% for geothermal. Maximum capacity factors of 20% for both batteries and LAES according to observed model run results.

TransitionZero

Methodology

How we modelled CFE in Taiwan

Key modelling design features

Relevant parameters of the 24/7 CFE model

- **Year of analysis:** 2030.
- **Time steps:** 8,760 hours/year, i.e. hourly.
- **Modelling framework:** PyPSA open-source linear optimisation of dispatch in copper-plated zones without intra-zone power flows.
- **CFE demand:** country-specific subset of demand from emerging sectors.
- **CFE demand profile:** Proportional to overall demand profile in each grid region.

Modelled nodes by country

Country	Grid regions	Interconnectors	
		Domestic	International
India	5	6	3 [1]
Japan	9 [2]	10	-
Malaysia	3	1	3
Singapore	1	-	2 [3]
Taiwan	1	-	-

[1] *Modelled as generators due to their low demand/supply levels.*
[2] *The analysis only covers the 9 interconnected price zones of the Japanese Mainland.*
[3] *Represents one existing and one planned interconnector, reflecting a conservative estimate of the import capacity that may be available to Singapore by 2030.*

Common inputs

Our models utilise the full suite of inputs required for power systems modelling

Technology

- Capacities
- Maximum build-constraints
- Renewable profiles
- Efficiencies
- Emissions factors

Financial

- Cost of capital
- CAPEX
- OPEX (FOM/VOM[1])

Demand

- Nodal hourly demand
- Commercial & industrial demand

National policies [2]

- Planned expansions
- Capacity mix targets
- Decarbonisation targets
- Transmission plans

[1] VOM also covers here fuel costs and carbon penalties.
[2] We will apply a delay of up to 5 years on policies that do not seem realistic, in consultation with our Working Group partners.

We run three sets of scenarios to test both supply and demand for CFE in 2030

Reference Scenario

A brownfield bus accounts for

Existing Grid and Generators in 2023

+

Transmission Capacity Expected by 2030

+

Generation Capacity Expected by 2030

+

Model-built Generation Capacity

Carbon-Free Electricity Scenarios

Where 3 different technology palettes are available

Technology Palette 1

Technology Palette 2

Technology Palette 3

Model-optimised capacity:
Annual Matching Regime

Where additional solar, onshore wind, battery storage can be built to meet 100% of participating C&I demand for the whole year

Model-optimised capacity:
Hourly Matching Regimes

Where xx% of C&I demand must be met with CFE for the each hour of the whole year

×

% of CFE hours matched is tested

70%
80%
90%
95%
99%
100%

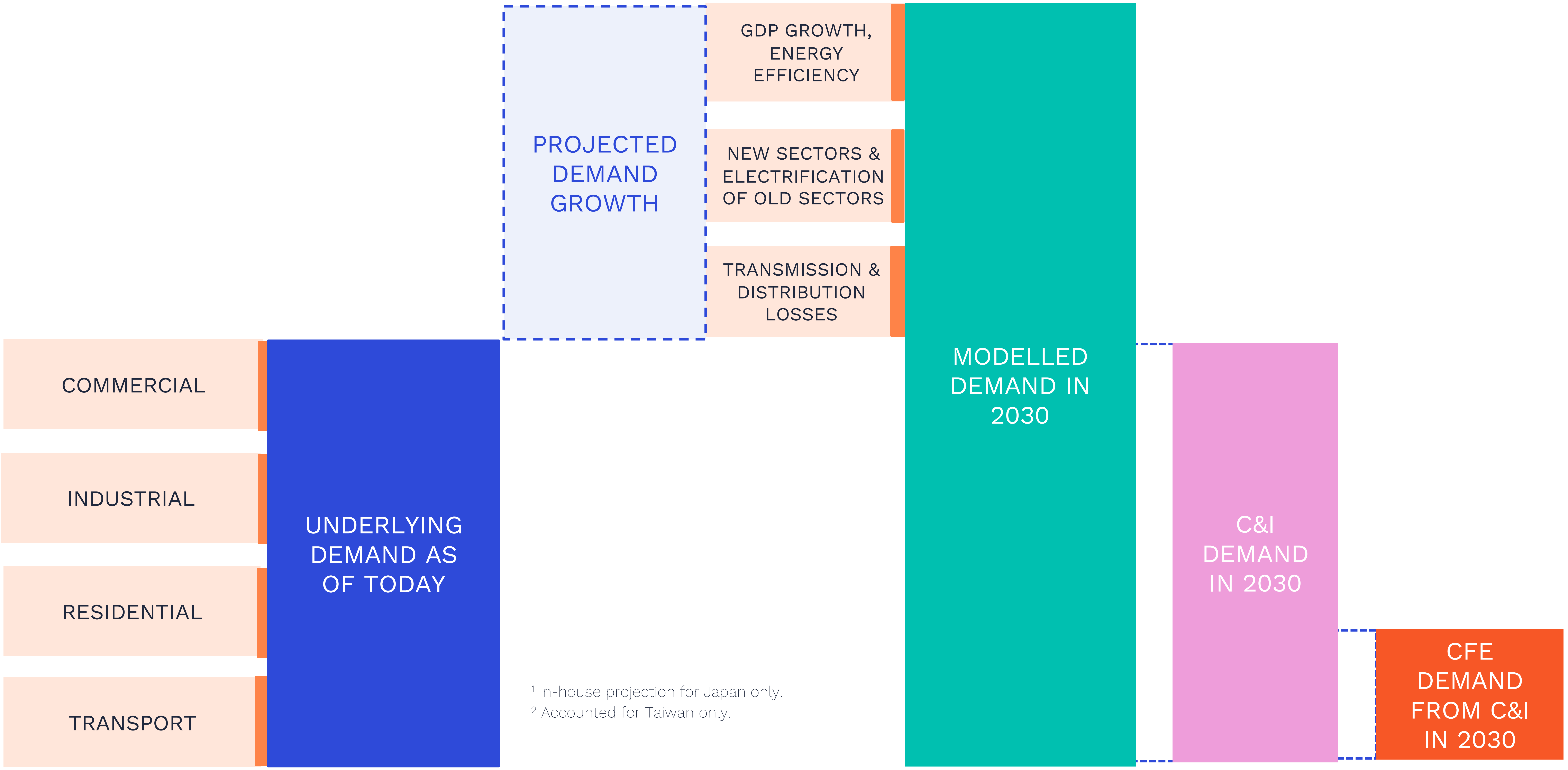
Notes

- CFE scenarios meet the participating C&I demand either on an annual or an hourly basis by building additional capacity (equivalent to procuring additional capacity through PPAs).
- Before modelling any CFE scenarios, we run a Reference scenario, allowing new-build on the brownfield bus only.
- For each technology palette the first CFE scenario is the Annual Matching Regime, which we run only once.
- We then run Hourly Matching Regimes starting with a CFE share of 70% and then rising to 100% for a total of 6 runs (see infographic on left).
- The total number of runs is 22, made up of 1 Reference Scenario and 7 matching regime runs each for each technology palette.

Demand in 2030

Our model considers demand for both conventional electricity and CFE

Illustration of components contributing to modelled final demand



[1] In-house projection for Japan only.
[2] Accounted for Taiwan only.

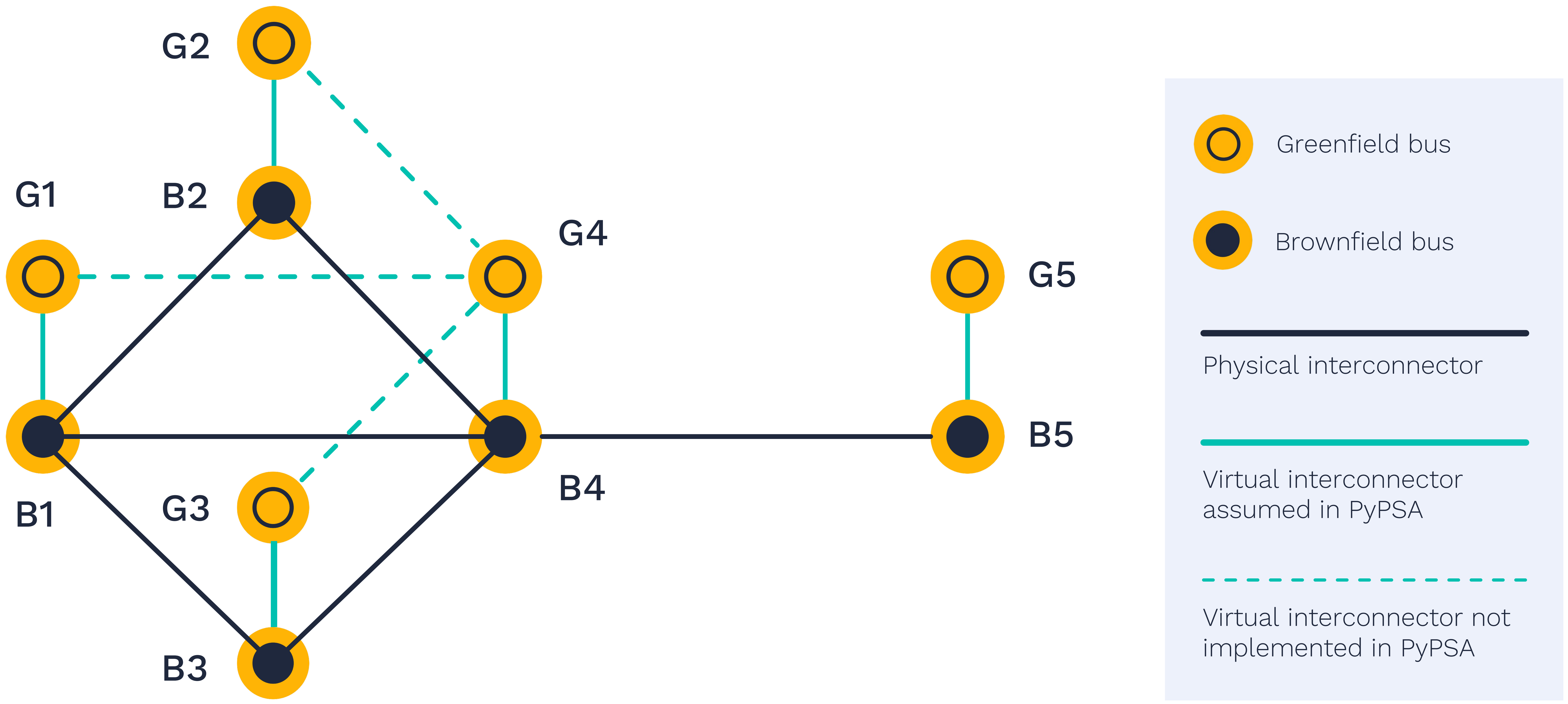
Notes

- Our demands for 2030 account for several sources of change from the present – either explicitly through in-house modelling[1] or by incorporating projections made by local authorities.
- In our Reference Scenario the model only seeks to meet demand for conventional electricity.
- In our CFE scenarios we expect that a certain share of C&I consumers switch to consuming only CFE, thereby triggering PPA developers to build new capacities.
- We derived a reasonable expected share for CFE demand relative to total demand through consultations with local stakeholders. The values are accordingly specific to each country.
- Actual CFE demand in each model run depends on the CFE% targeted in each Hourly Matching Regime.

Market	CFE volume [TWh]	CFE % [relative to 2030 demand]
India	122 TWh	5%
Japan	29 TWh	3%
Malaysia	14 TWh	5%
Singapore	3.5 TWh	4%
Taiwan	16 TWh	5%

Connections among buses

We break down complex markets featuring multiple zones connected through interconnectors into multiple linked buses

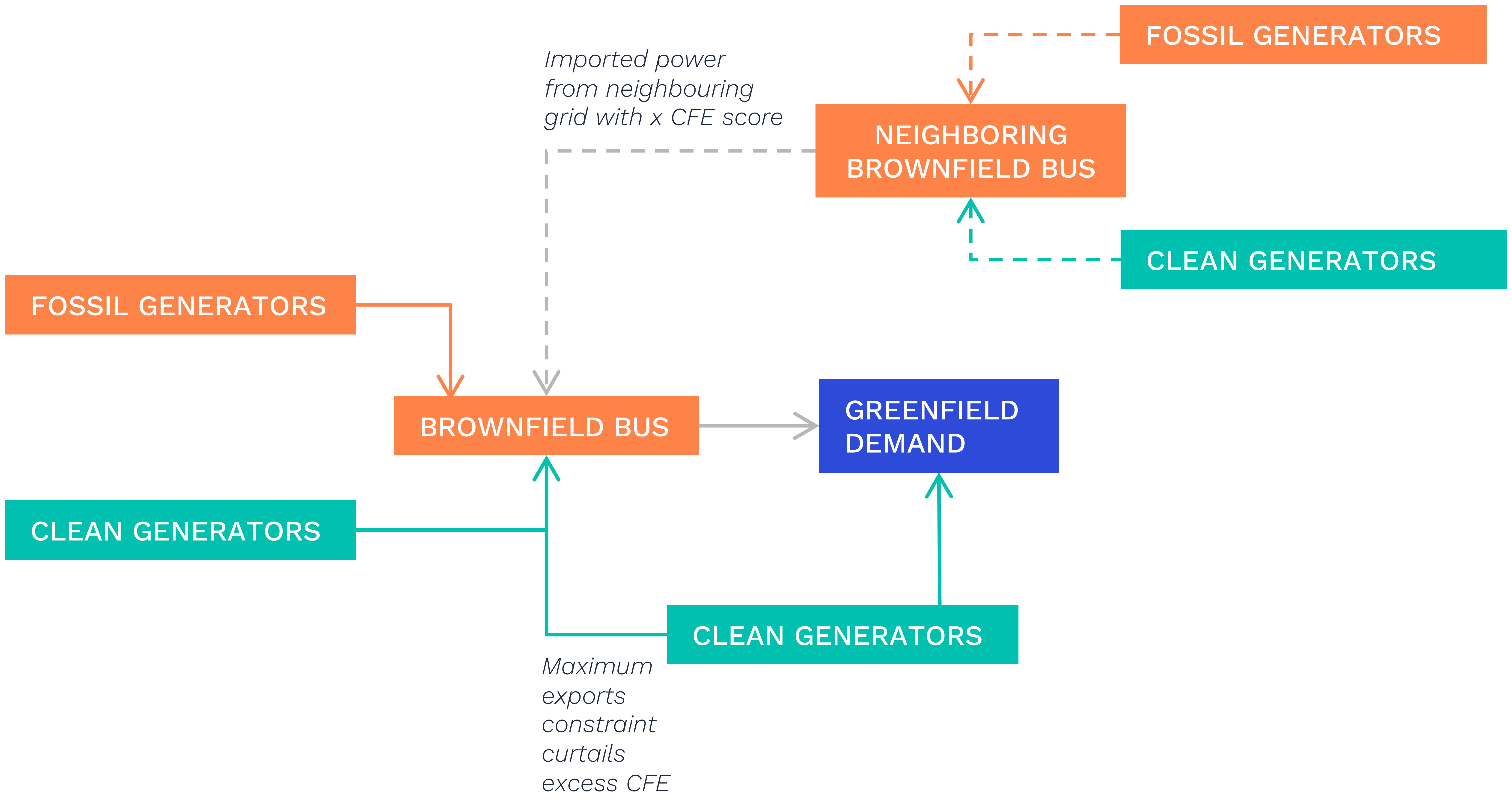


Notes

- In PyPSA we implement brownfield buses connected through links in a topology that reflects real-world grid zones and the interconnectors between them.
- The brownfield buses contain the same generators and loads as in the real world.
- To each brownfield bus we attach a single virtual greenfield bus to house generators financed through the CFE PPAs by interested C&I consumers located in the original grid zone.
- In this project greenfield generators can only supply C&I consumers on the brownfield bus they are directly connected to, i.e. there are no linkages to other greenfield or brownfield buses.

Procurement across links between buses

Our model allows for bi-directional trade between the greenfield and brownfield buses



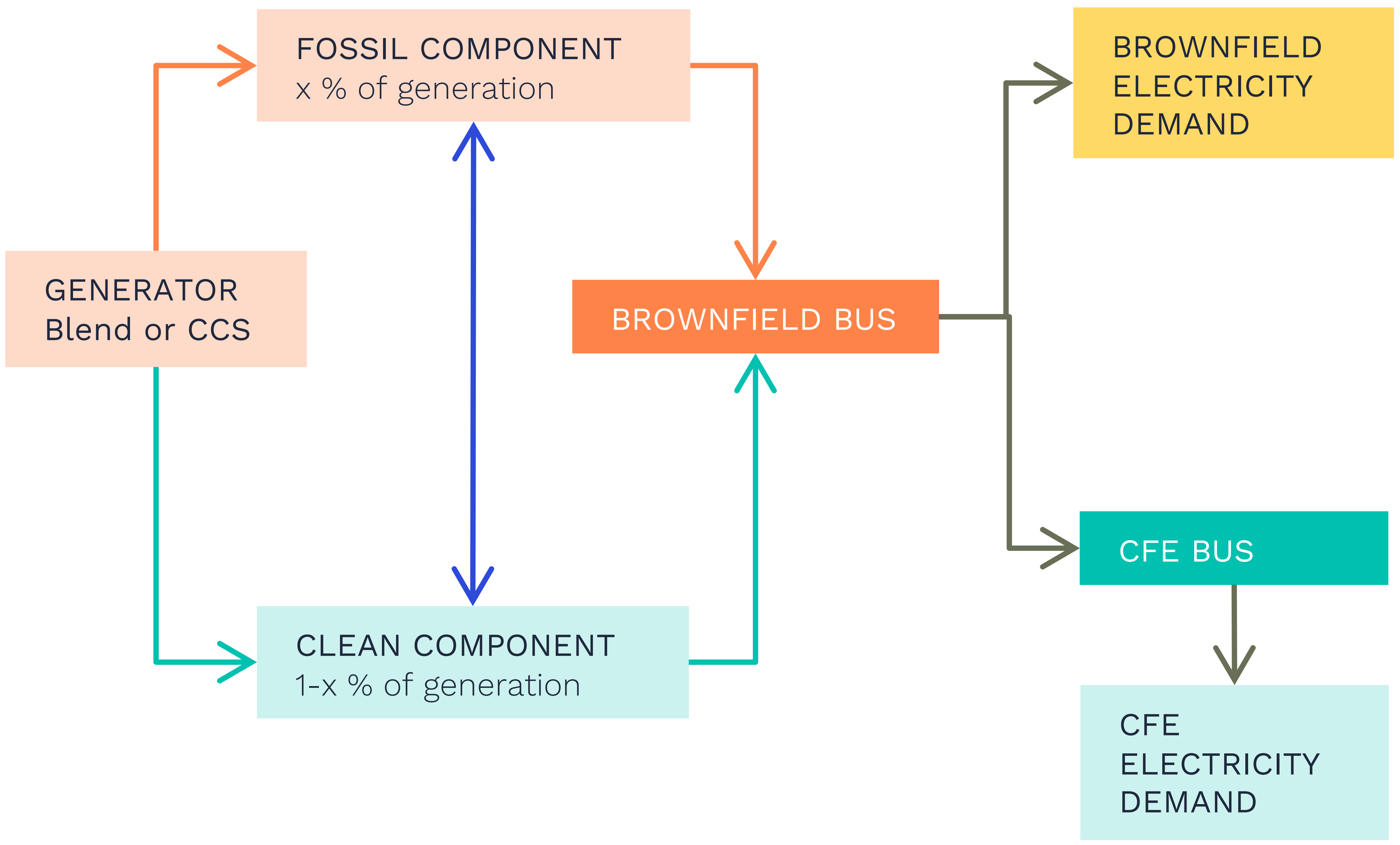
Notes

- C&I consumers can use brownfield procurement to top up insufficient PPA generation.
- If their local grid is interconnected with another grid, then the CFE score of their brownfield procurement will be affected by the CFE score of the net imports from that other grid.
- For certain countries, we allow sellback **of excess generation back to the grid**, reflecting a conservative assumption based on grid technical constraints in handling additional exogenous generation at both hourly and annual scales. This maximum sell-back is set at 20% for hourly CFE in India, and 15% in Malaysia and Singapore.
- Reflecting local market conditions this limit is set to 100% of C&I load in Japan and Taiwan. In Japan new renewable plants are increasingly urged by the government to sell their generation on the wholesale market, whereas in Taiwan Taipower buys up generation at fixed feed-in tariffs.

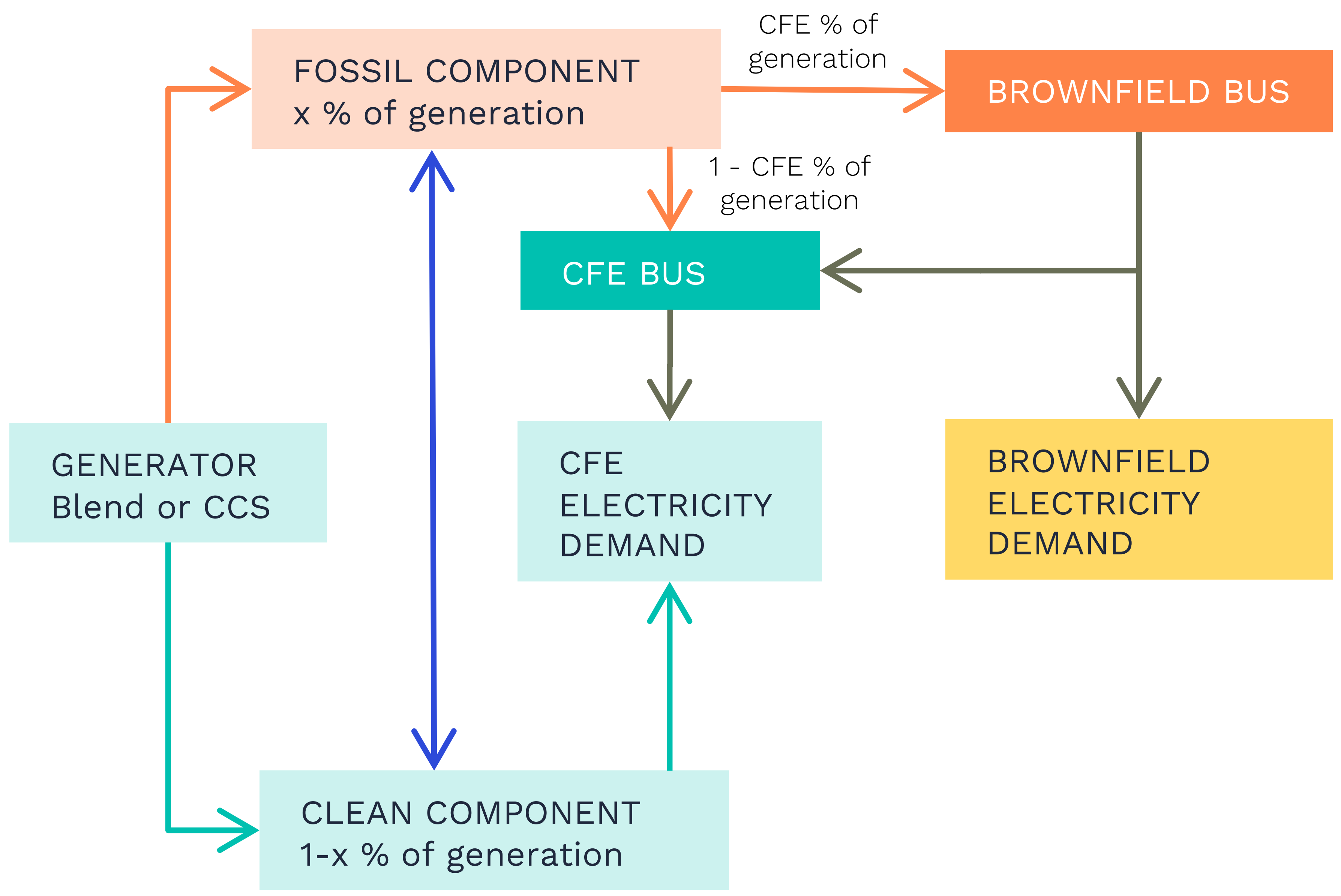
CFE scoring for TP3’s innovative thermal plants

We ensure that only an appropriate share of generation from low-carbon generators can be used to meet CFE demand

Built on the brownfield



Built on the greenfield



[1] Expressed as the CFE share of the hourly matching regime.
[2] For the 100% CFE hourly matching regime the model will allow only CFE consumption on the CFE bus, but for lower matching regimes some emitting generation is permitted.
[3] As a share of energy, derived from policy objectives of the Japanese authorities. Technologies available for TP3 differs per country.

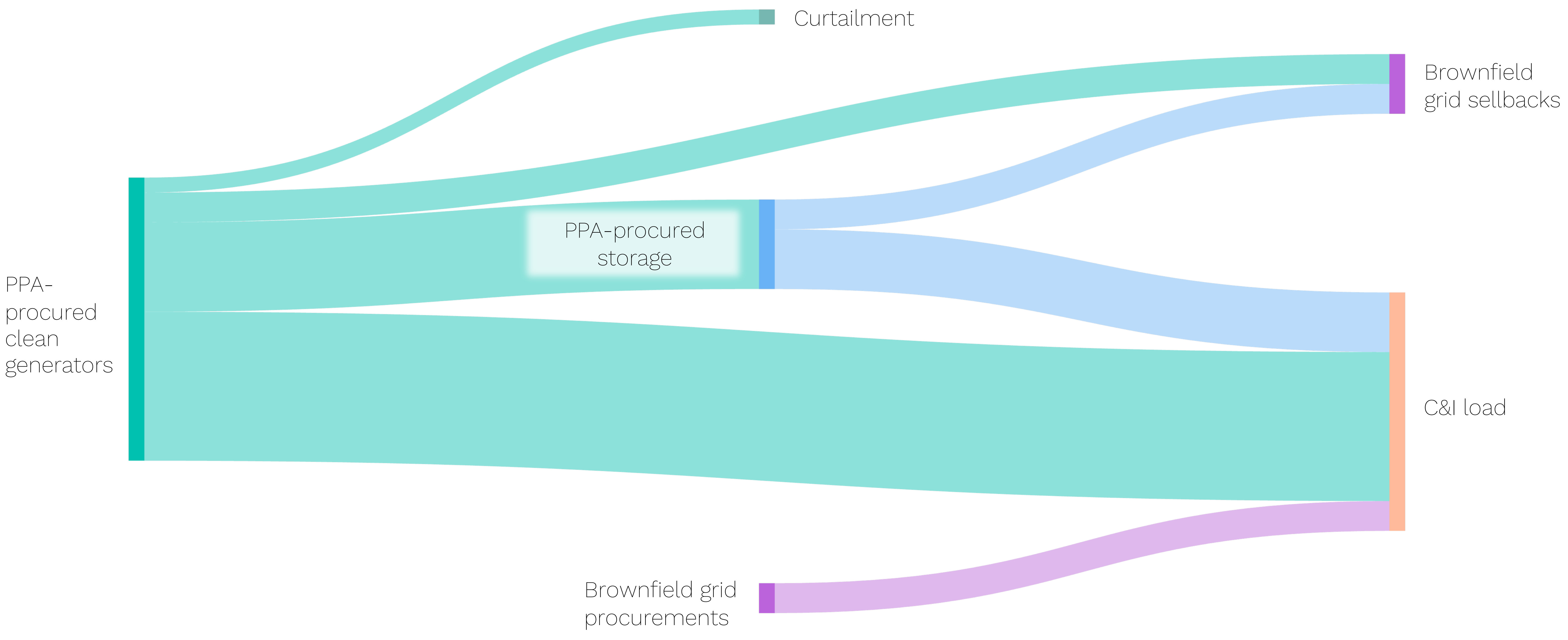
Notes

- Whereas loads on the brownfield bus consume any kind of electricity, consumers on the CFE bus want to meet a minimum share of their consumption from CFE[1].
- The generation from plants that blend fossil and non-fossil fuels and CCS plants with imperfect capture rates cannot be said to be 100% CFE.
- For each such plant we implement a CFE generation ratio that is fixed at all time steps.
- For plants on the brownfield bus (present in the Reference Scenario) their generation mingles with all other pre-existing plants’ generation, affecting the CFE % of the brownfield, and this total generation may then flow into the CFE bus depending on the target matching regime.[2]
- For plants on the greenfield bus (present in technology palette 3) the non-CFE share of their generation flows immediately to the brownfield bus, from where it may return to the CFE bus depending as in above point on the target matching regime.

Asset class	CFE share[3]
Coal-ammonia co-firing	20%
Gas-hydrogen co-firing	10-30%
CCS	70%
Coal-biomass co-firing	15%

Energy flows and costs for the C&I load

Sankey diagram showing indicative energy flows between clean generators, storage units, the grid, and the C&I load



Relevant formulas

- In calculating the unit cost of electricity supplied to the C&I consumer, the C&I consumer could handle the grid procurements themselves, and the PPA manager handles the PPA supply and sellback revenue from excess supply. This would lead to the following unit cost calculation:

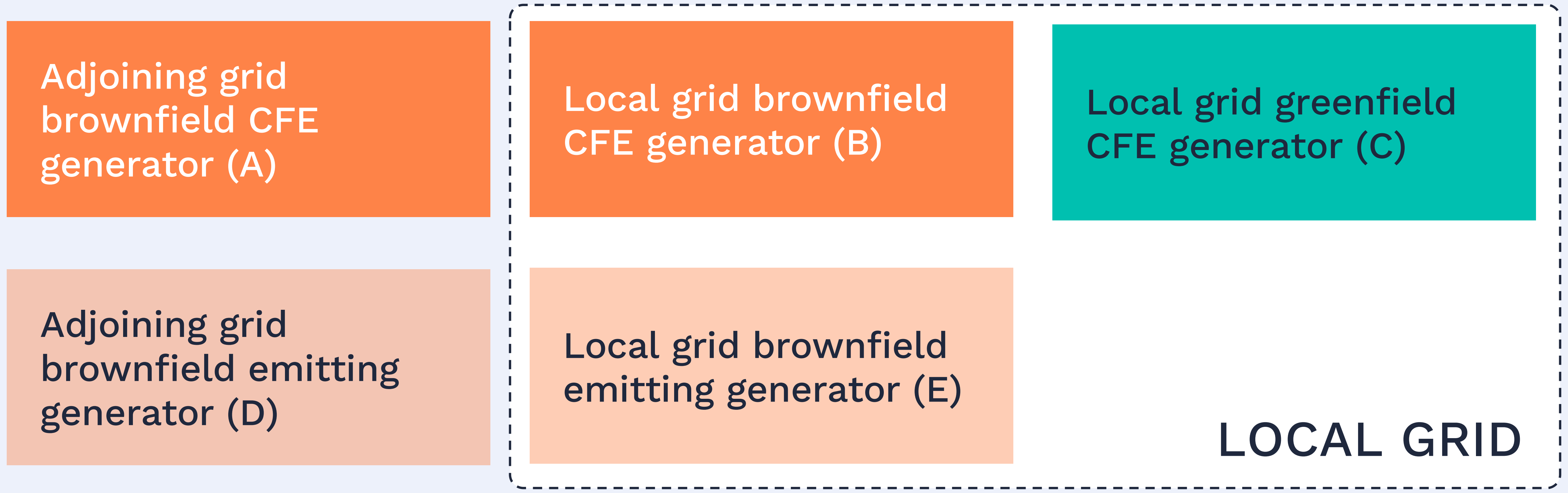
$$\text{Unit cost} = A \times \frac{\text{capex + opex + grid export revenue}}{\text{C\&I load} - \text{grid imports} + \text{grid exports}} + (1-A) \times \frac{\text{grid import costs}}{\text{grid imports}}$$

$$\text{Where } A = \frac{\text{C\&I load - imports}}{\text{C\&I load}}$$

- This splits the electricity supply into the two components which come from the PPA supply and the grid respectively, which are then weighted by the proportion by which they supply the C&I load.

Grid CFE score

We iterate to avoid the CFE build-out in adjoining grid zones from creating a nonconvex modelling problem



$$ImportCFE_t = \frac{A_t}{A_t + D_t}$$

$$CFE_t = \frac{B_t + ImportCFE_t * import_t}{B_t + E_t + import_t}$$

- To determine whether C&I consumers can use the brownfield grid to meet their target CFE score we calculate a “grid CFE score”, showing what ratio of all brownfield generation comes from CFE sources
- When C&I consumers use brownfield procurement to top up insufficient PPA generation, if their local grid is interconnected with another grid, then the CFE score of their brownfield procurement will be affected by the CFE score of the net imports from that other grid
- However, because all grids are building out CFE capacity to meet matching regime requirements, this creates a nonconvex modelling problem
- We avoid this problem by treating the grid CFE score as a parameter that is iteratively updated, with convergence expected after 2 iterations

Limitations of the study

We have taken several decisions to simplify the scope of our study

Considerations	Decision
Multi-period investment optimisation	Not included: We only model one step from the calibrated base year of 2023 to the target year of 2030
Trading of Energy Attribute Certificates	Not included
Demand shifting (in time and space)	Not included
Impact of asset age on additionality	We are not exploring Climate Group RE100 guidance to treat all renewable assets younger than 15 years as additional
CFE status of discharges from storage assets on brownfield buses	Not included

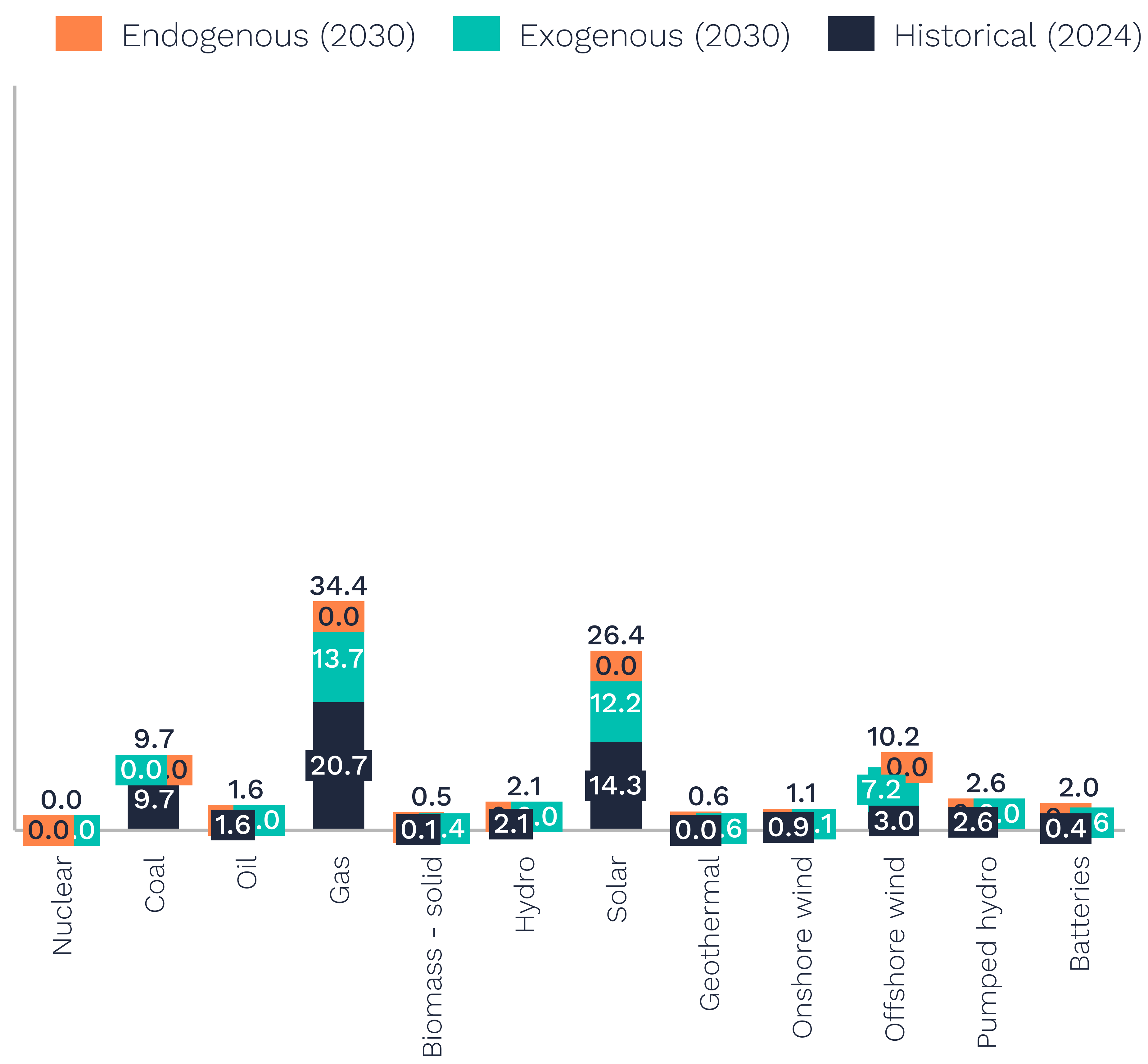
Modelling results

Deep-dive analysis into the national level findings

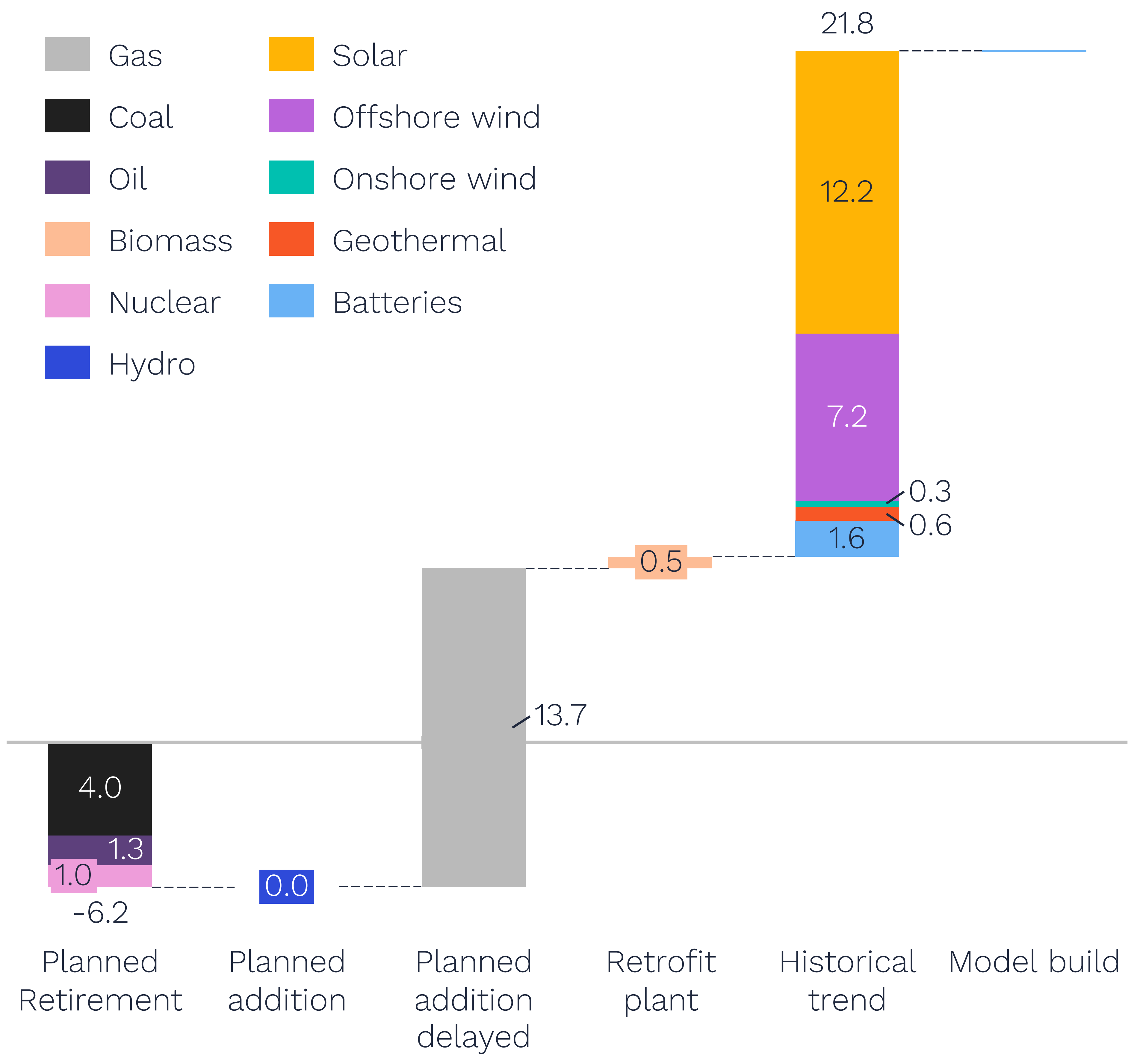
Reference Scenario: Generators and storage capacities

Our analysis starts with the composition of the power system before any CFE demand

Installed capacities (GW)



Breakdown of 2030 exogenous capacities (GW)



Notes

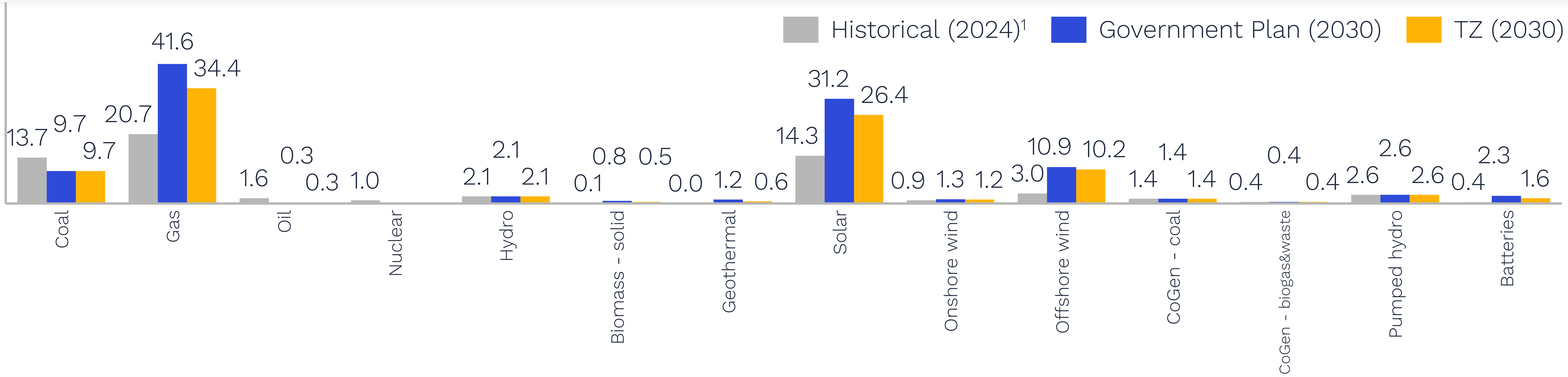
- In our initial approximation of Taiwan's 2024 power system, we reconcile the MOEA E-STAT figures to derive a capacity mix that best represents the grid supply.
- We model the entire island as a single node, assuming electricity generated at any location can be transmitted seamlessly to any demand centre. This simplification is supported by the fully interconnected nature of the regional grids, with the central region serving as the primary hub for transmission across the island.
- We acknowledge the government's planned capacity mix for 2030 which we have followed for planned retirement of coal, oil power plants by 2030. However, for gas and most renewables, we have conservatively adjusted it downward based on historical build rates to derive a more realistic projection.
- We have also allowed PyPSA to endogenously build new capacity to meet projected 2030 demand – but our conservative expectations yield enough capacity to meet demand, resulting in no additional capacity expansion.

Source: TZ modelling and desk research.

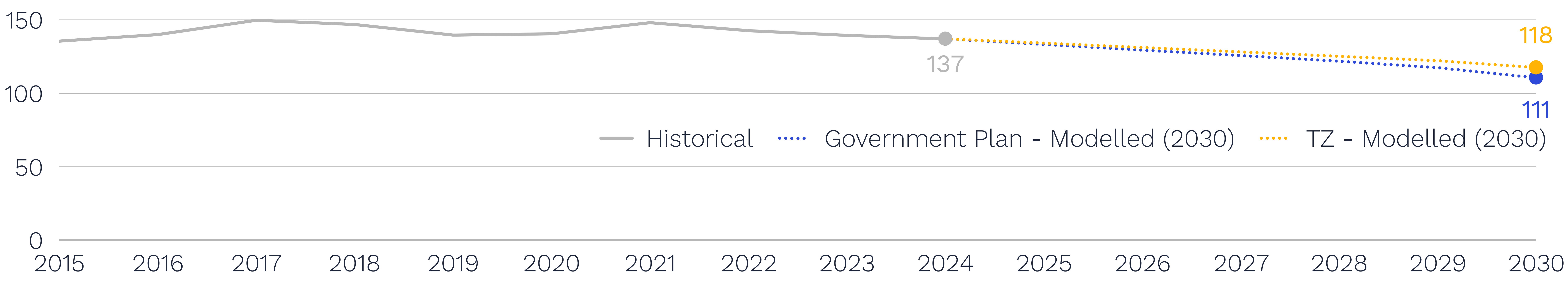
Reference Scenario: Alternative capacity mix and emission evolution

No additional endogenous capacities were built in either the government plan or TZ scenarios, indicating that existing and planned capacity is sufficient to meet demand

Comparison between installed capacities across different technologies and scenarios (GW)



Comparison of emissions evolution across different scenarios (MTCO2e)



Notes

- While the Taiwanese government has not set clear 2030 generation mix targets, we estimated one based on the installed capacity targets set for each technology and applied the same 2022 weather year demand and generation profile as in the TZ scenario.
- Analysing Taipower's official 10-minute interval reports on asset-level power generation, we understand that surplus electricity from autoproducing cogeneration plants — primarily coal, biogas, and waste — also supports the grid intermittently. However, this output is reported as one single aggregated category, without distinguishing between the individual fuel types.
- To address this, we disaggregated the generation by applying the reported 2023 peak reliable capacity[2] split among those fuel types. For 2024, due to reporting delays, we used the highest recorded hourly generation of the year as a proxy for peak reliable capacity.
- Our Reference Scenario shows grid emissions in 2030 decrease by approximately 14% compared to 2024 levels. In contrast, the government plan would see a 19% reduction over the same period.

Source: TZ modelling.

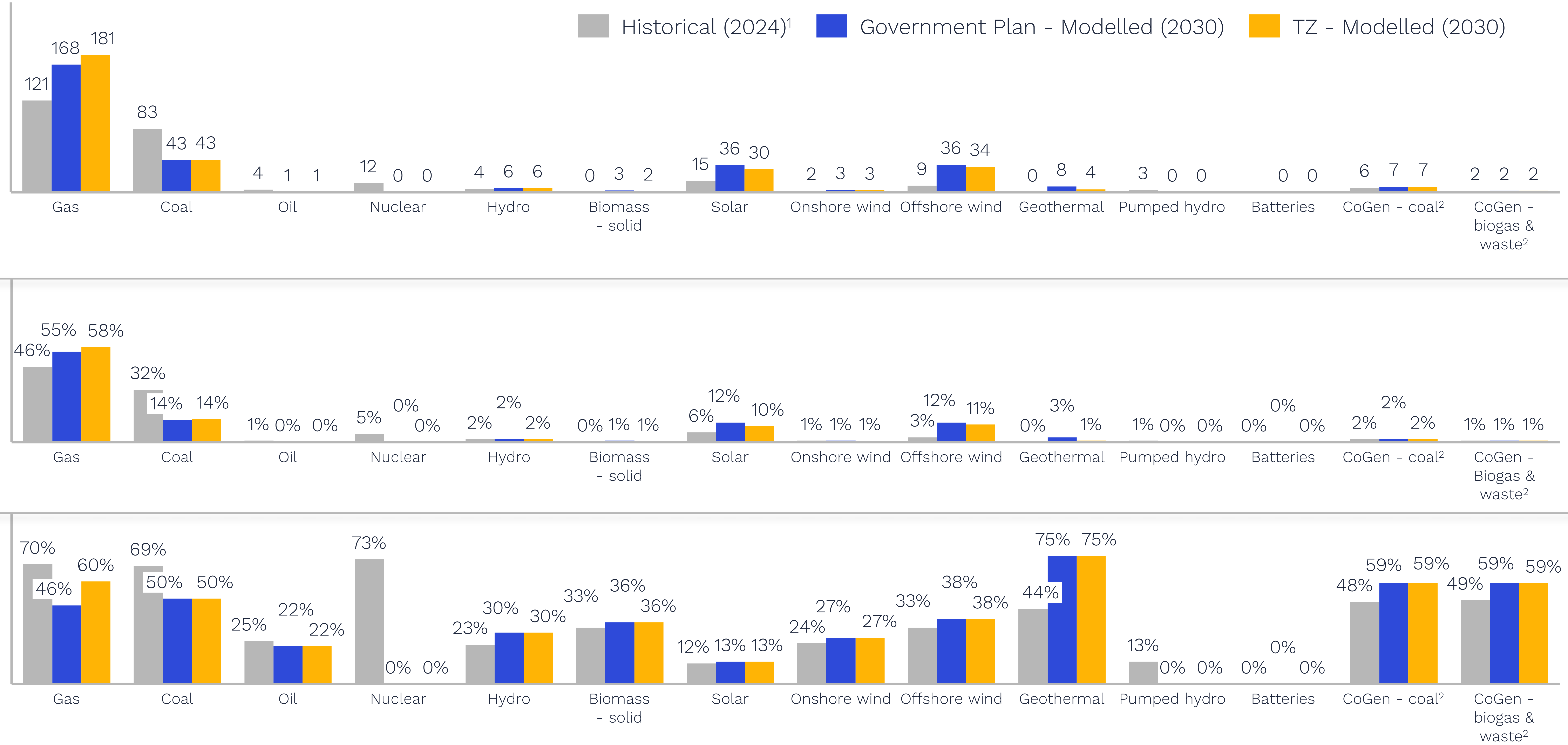
[1] Historical data is sourced from MOEA E-STAT. We exclude captive thermal power plants, as our analysis focuses solely on units primarily used for grid-connected electricity generation.

[2] The minimum expected contributing capacities rather than installed capacity as they are highly uncertain.

Reference Scenario: Generation mix

Our Reference Scenario features a higher share of gas compared to both the current and the inferred 2030 government scenarios, reflecting our conservative adjustment to the government's renewable energy targets

Generation across different technologies and scenarios (TWh, % of total generation, % of year)



Notes

- To account for operational features such as outages and must-run conditions, we apply both maximum and minimum annual utilisation constraints on thermal power plants — inherited from the 2024 calibration — in both the government plan and our reference scenarios.
- We use a single weather-year profile for intermittent renewables like solar, hydro, onshore, and offshore wind while applying annual utilisation rates for biomass and geothermal, reflecting their relatively stable generation patterns.
- We have decided to treat cogeneration the same as other intermittent renewables whereby we construct unique hourly generation profile throughout the year using 2022 weather year. (See our input section for an explanation of our weather year choice.)
- Our reference scenario indicates that the share of renewables nearly doubles, from 13% to approximately 25% of total generation, but remains lower than the ~ 31% in the government plan scenario, mostly due to our more conservative estimations for the build rates of renewables, based on historical trends. Gas continues accounts for more than half of total generation in both scenarios.

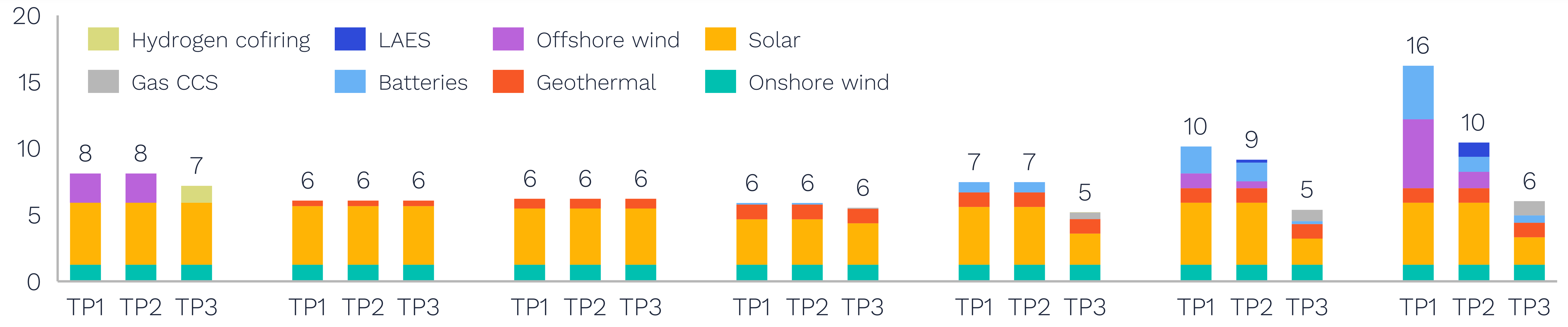
Source: TZ modelling.

[1] Historical data is sourced from MOEA E-STAT. We exclude captive thermal power plants, as our analysis focuses solely on units primarily used for grid-connected electricity generation.

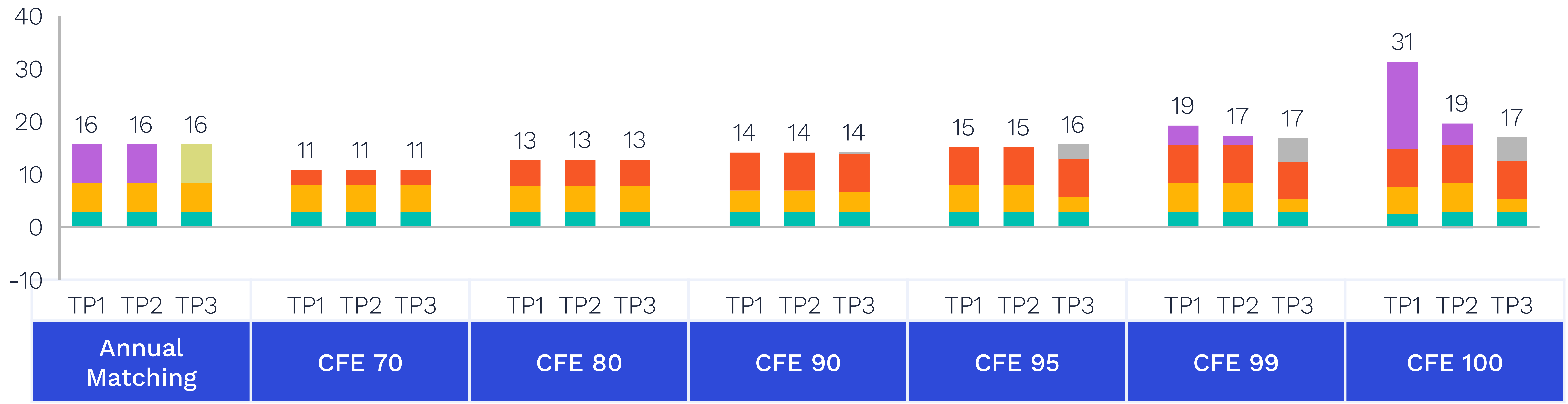
[2] For cogeneration plants, only surplus electricity supplied to the grid is considered. Since these values are not reported in MOEA E-STAT, we supplement them using data from third-party source Electricity Maps.

The rapid buildout of offshore wind and batteries needed to exceed CFE 90 can be eased by long-duration storage and CCS

Greenfield build-out – national total (GW)



Greenfield generation – national total (TWh)



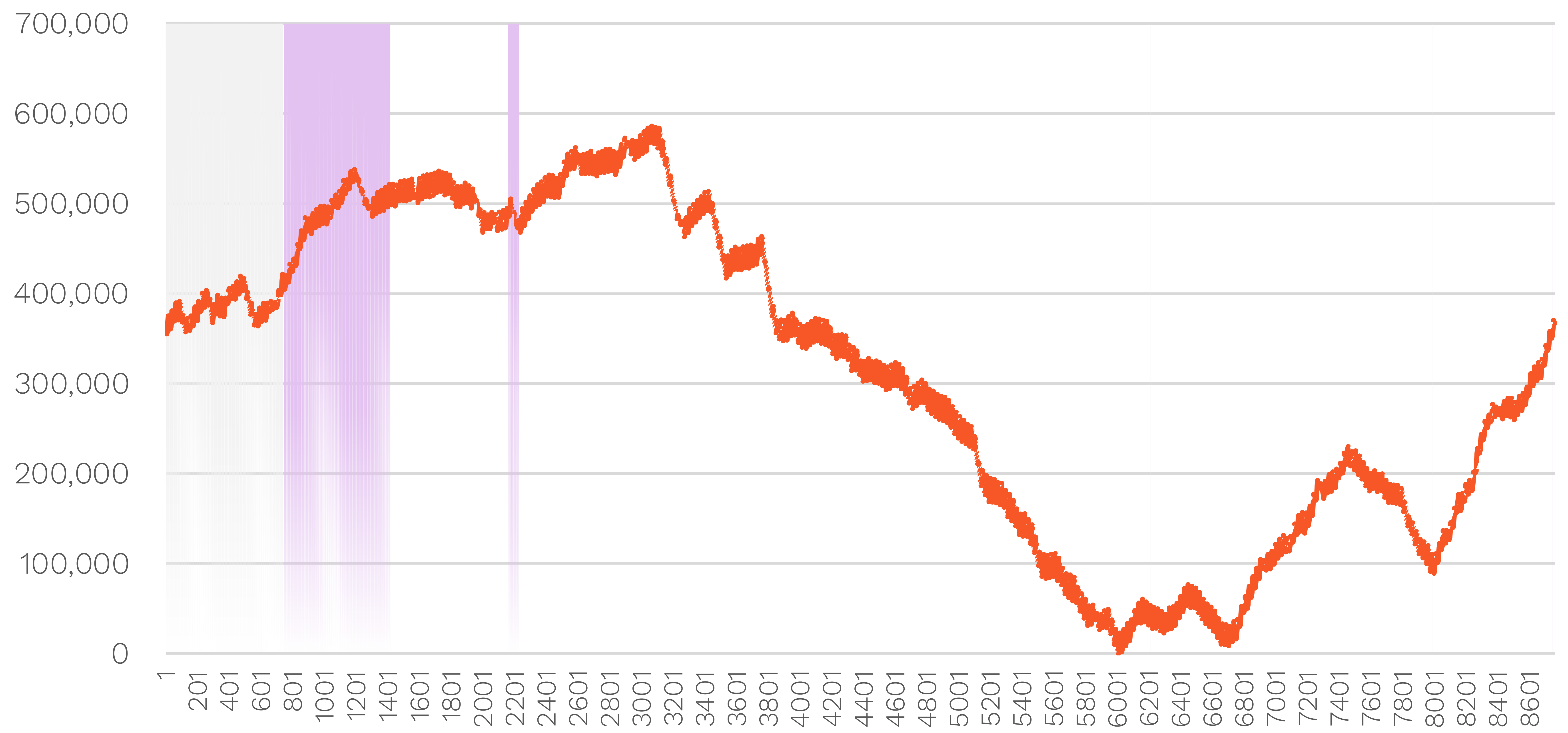
Notes

- Under hourly matching, geothermal is preferred over offshore wind despite its slightly higher LCoE (US$133/MWh vs US$128/MWh). Its weather-independent, reliable generation profile reduces the need for storage and pairs well with brownfield imports. In annual matching, where weather variability matters less, offshore wind becomes the cheaper and preferred option.
- Under hourly matching, storage makes an appearance once CFE scores rise above 90%, when the brownfield grid can no longer provide enough CFE. Meanwhile offshore wind emerges only at the two most stringent CFE scenarios when all other renewable options have maxed out their build constraints.
- Adding liquid air energy storage (LAES) in TP2 reduces the need for offshore wind and battery capacity due to its longer storage duration.
- TP3 sees gas CCS entering the mix starting at CFE 95, replacing the need of both offshore wind + batteries in TP1 or offshore wind + LAES in TP2, underscoring the advantage of dispatchable technology in avoiding overbuild.

Source: TZ modelling.

Liquid air energy storage soaks up energy early and stores it for extended periods to manage seasonal demand peaks

LAES hourly state of charge in Taiwan under CFE 100 (MWh)



Notes

- In this project we assume that the consumption profile of C&I consumer interested in 24/7 CFE matches that of other consumers, but if the two diverge the utilisation profile of long-duration energy storage may shift considerably.
- Beyond supplying the greenfield differently, storage activity may also change due to the potential for trading with the brownfield.

Source: TZ modelling.

CAPEX is the main cost driver, but long-duration storage and dispatchable generation can significantly reduce it

System-wide costs and benefits[1,2] (billion US$)

Notes

- Costs rise sharply under TP1 once onshore wind, solar, and geothermal potential is fully used, as expensive offshore wind must be added to compensate for low summer capacity factors. Some costs are offset at the system level through sales of excess offshore wind to the grid, which lowers fuel use, but the need to meet peak demand with limited alternatives makes achieving CFE 100 under TP1 particularly costly.
- The need for dispatchable technologies rises sharply at the highest CFE levels. In TP1, the additional storage CAPEX required to move from CFE 99 to 100 — about US$0.42 billion — matches the net system cost of reaching CFE 80.
- Moving beyond regular batteries lowers CAPEX. In TP2, the addition of LAES cuts total CAPEX by 38%, down to US$2.9 billion from US$4.7 billion in TP1, as greater storage capacity reduces the need to overbuild offshore wind to cover summer lulls.
- With the inclusion of CCS in TP3, CAPEX is reduced by 61%, from US$4.7 billion in TP1 to US$1.8 billion, as CCS eliminates offshore wind and LAES entirely, and significantly reduces the reliance on hybrid solar-battery systems.

Source: TZ modelling.

[1] These comprise all capital, operational, and fuel expenditure of the entire system, including PPA assets.
[2] CAPEX figures shown are expressed in real 2023 money base and annualised, based on the assumed lifetime of individual assets and discounted to present value.
[3] Net system costs are calculated from the sum of CAPEX paid by the C&I consumer and fuel cost savings to the grid.

Costs increase for consumers as CFE scores rise, but less significantly than for capacities

PPA unit costs (USD/MWh)

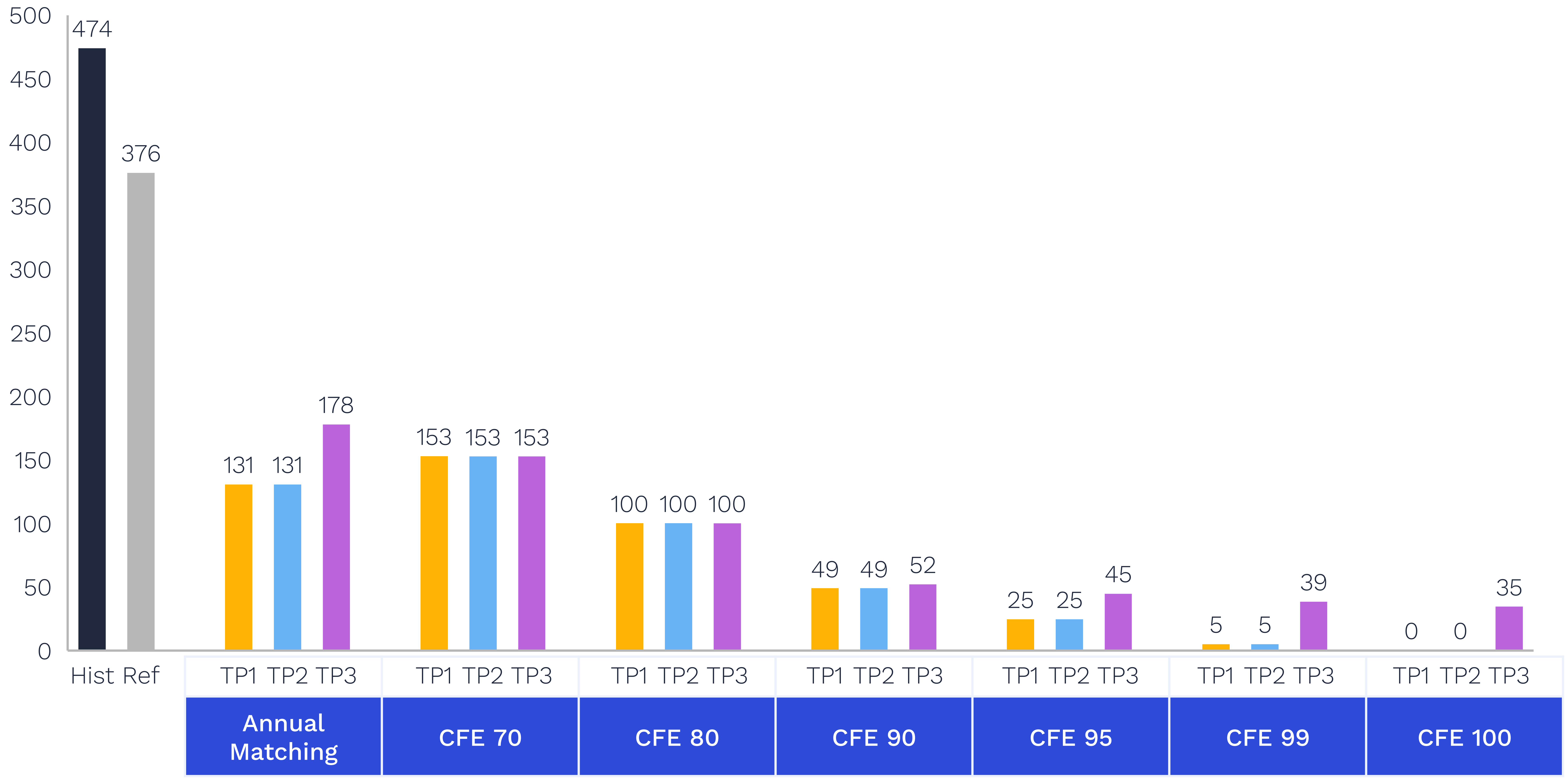
Notes

- While nationwide capacity requirements rise 2.7-fold under TP1 — from 6 GW at CFE 70 to 16 GW at CFE 100 — net PPA unit costs increase more moderately, by 1.4 times, from US$84/MWh to US$116/MWh
- Adding LAES in TP2 slightly increases cost escalation, as lower PPA CAPEX and OPEX are more than offset by reduced PPA sales to the grid. The equivalent rise is 1.6 times, from US$84/MWh to US$138/MWh.
- Under TP3, costs rise 1.5 times, from US$84/MWh to US$122/MWh. Offtakers pay less PPA CAPEX by using dispatchable technologies and avoiding renewable overbuild, but fuel costs for CCS plants and reduced PPA sales to the grid push net PPA unit costs above TP1, though still below TP2.

Source: TZ modelling.

Procuring higher shares of CFE to cover C&I load progressively eliminates Scope 2 emissions

Emission intensity of C&I electricity consumption (gCO_2e/kWh)



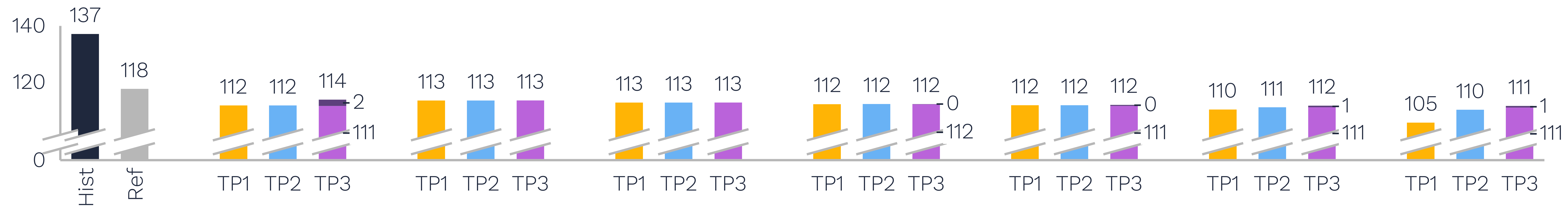
Notes

- Participation in any matching regime can reduce emission intensity of offtakers by more than half compared to the Reference Scenario.
- Under both TP1 and TP2, annual matching delivers lower emission intensity than CFE 70 (153gCO2e/kWh vs 131 gCO2e/kWh), because annual matching is designed to cover 100% of the C&I load, while CFE 70 allows some fossil-backed grid procurement.
- From CFE 80 onward, hourly matching achieves lower emissions intensity than annual matching. As hourly requirements become more stringent, intensity falls steadily, reaching zero at CFE 100 under TP1 and TP2.
- The emission intensity cannot physically reach zero under TP3, as the use of blended fossil fuels creates unavoidable emissions due to leaks from the CCS system.

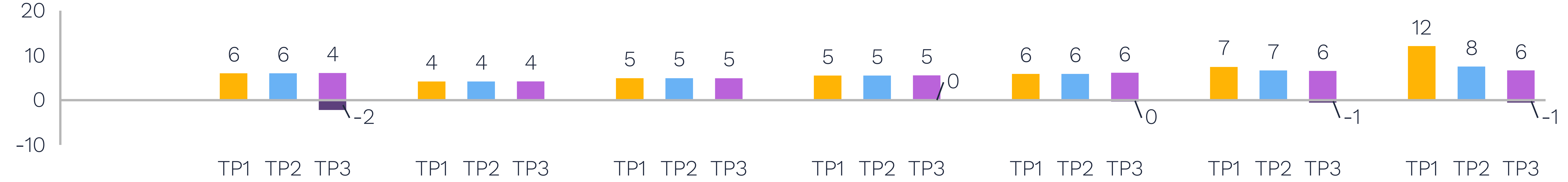
Source: TZ modelling.

The positive impacts of 24/7 CFE on emissions goes beyond eliminating the climate impact of new buildout

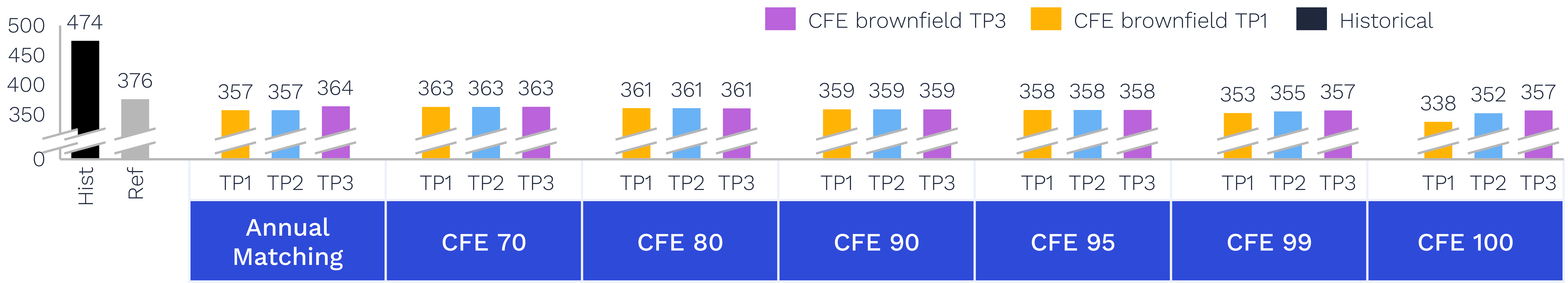
National emissions ($MtCO_2e$)



National emissions savings ($MtCO_2e$)



National emissions intensity (gCO_2e/kWh)



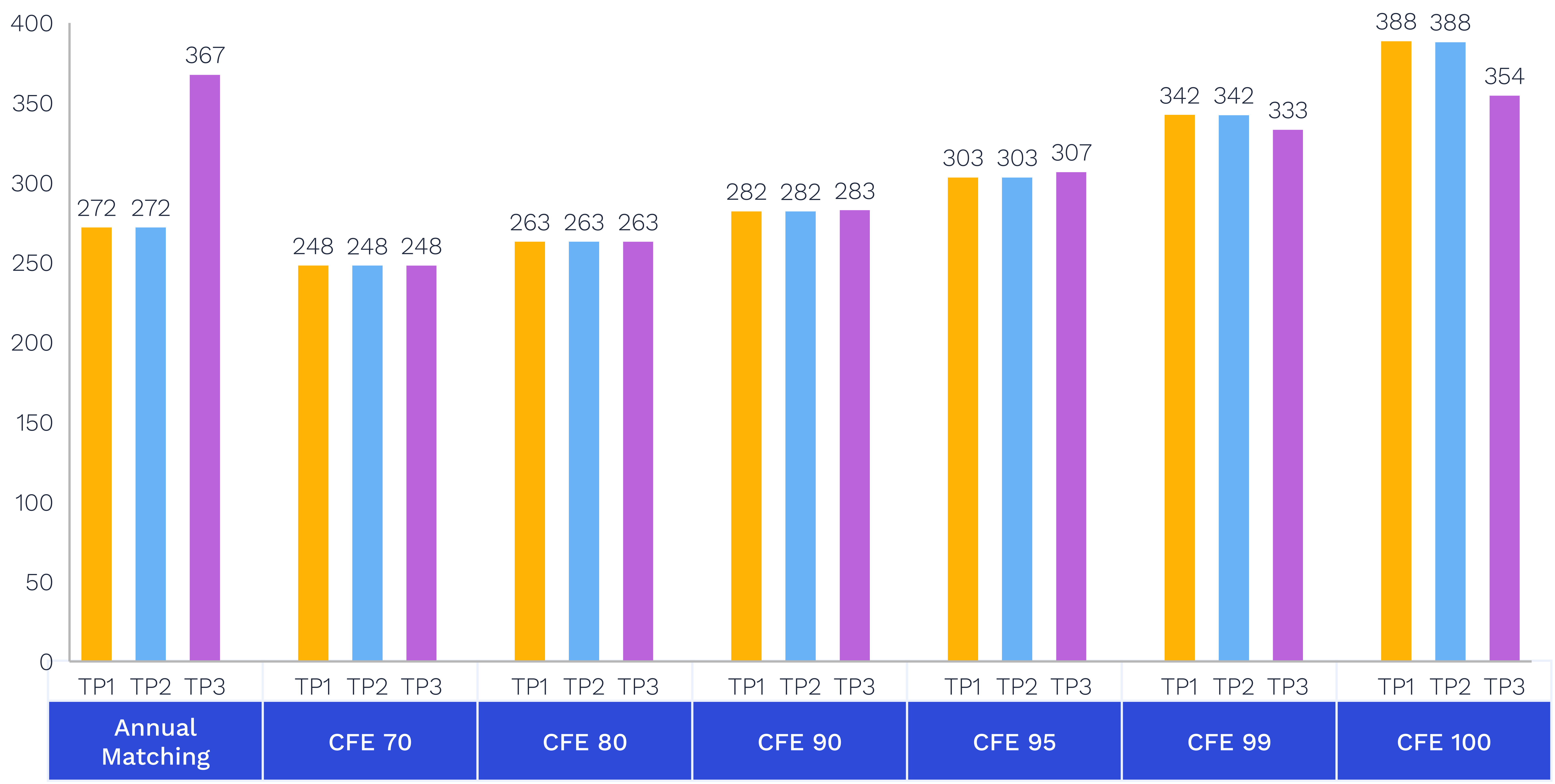
Notes

- For TP1, the emissions impact is lowest at CFE 70 because here C&I consumers continue to rely the most on grid electricity, which continues to be powered by the same generators as in the Reference Scenario.
- As CFE scores increase under TP1, the emissions impact of excess CFE generation sold back to the brownfield grid further pushes up the emissions impact as it displaces the marginal fossil generators on the brownfield.
- Under the CFE 100 scenario the emissions impact is the highest because the push towards hourly matching incentivises more offshore wind capacity to cover summertime generation lulls after all other renewables have been exhausted; this results also in more excess CFE generation that is then sold back to the grid.
- TP2 reduces national emissions less than TP1 because long-duration storage soaks up excess CFE in many hours, releasing it later for C&I consumers' use, rather than releasing it for immediate consumption by brownfield consumers.
- TP3 provides lower emissions cuts relative to the previous palettes because off-takers are now directly responsible for leaked emissions, reducing the emissions impact.

Source: TZ modelling.

Across all technology palettes, abatement costs rise gently with higher CFE scores, with minor savings observed via CCS

Abatement cost born by all off-takers[1] (USD/tCO_2e)



Notes

- In TP1 abatement costs increase from CFE 70 to CFE 100, with the 56% growth largely aligning with the evolution of system costs (circa 40% over the same interval).
- The introduction of LAES in TP2 marginally reduces abatement costs at CFE 100 compared to TP1. While LAES reduces the renewable overbuild seen in TP1, it also lowers the volume of excess CFE available for sale back to the regular grid. This decreased revenue pushes up overall costs.
- Adding CCS in TP3 lowers abatement costs by 9%, from US$388/$tCO_2e$ to US$354/$tCO_2e$. CCS reduces the need for costly overbuild of renewables and storage, and these savings outweigh the impact of its higher residual emissions, leading to a lower cost per tonne of CO_2 avoided.

[1] Carbon abatement cost is calculated as the CAPEX and OPEX expenditures of all PPAs divided by tCO2e of nation-wide system emissions savings.

Source: TZ modelling.

Conclusions

Incorporating CFE 24/7 into Taiwan's energy transition

Carbon free electricity can bring benefits to both the system and C&I consumers

Supporting policy and clear price signals are needed to further incentivise CFE procurement

01

Diversifying into offshore wind and geothermal is critical to achieve hourly matching.

Given highly constrained potential for onshore wind and solar, our analysis reveals that geothermal is fundamental to all hourly matching levels and offshore wind is necessary to achieving the most stringent hourly matching goals.

Taiwan's track record in offshore wind rollout and recent target setting on geothermal provide a solid foundation for hourly matching. However, rising development costs, supply chain constraints, and resource uncertainties pose significant execution risks to investors. Future policy frameworks must therefore focus on de-risking these challenges and strengthening investor confidence.

02

CFE 80 is not only cleaner for consumers, but also cheaper than electricity tariffs, and saves the system US$1 billion per year and 5 $MtCO_2e$.

The unit cost required for C&I consumers to achieve 80% hourly matching is lower than the lowest historical electricity tariff in the past six years, while also eliminating nearly 75% of Scope 2 emissions. Nationally it yields system-wide fuel savings worth nearly US$1 billion per year.

Given Taiwan's existing 15-minute interval matching mechanism, only minimal system adjustments are needed for implementing hourly matching. However, the current exclusion of batteries in T-REC matching presents a barrier for C&I consumers to fully commit to hourly CFE 80 goals.

03

Widening technological palettes brings renewable buildouts within an achievable range even for CFE 100.

Under TP1, CFE 100 comes within reach if C&I consumers accelerate solar and geothermal deployment by five years, unlock the full potential of Taiwan's onshore wind sites, and propel offshore wind growth beyond current trajectory. Including long-duration storage or innovative thermal can significantly reduce the scale of renewable buildout.

Gas CCS can outperform LAES and other cofiring options in this regard, more than halving the total renewable build-out. However, it cuts fewer emissions, and its ultimate performance is strongly sensitive to assumptions. Policy development around CCS should be mindful of these challenges.

Sensitivity analysis

What happens with alternative assumptions?

Technology risk 1: Geothermal

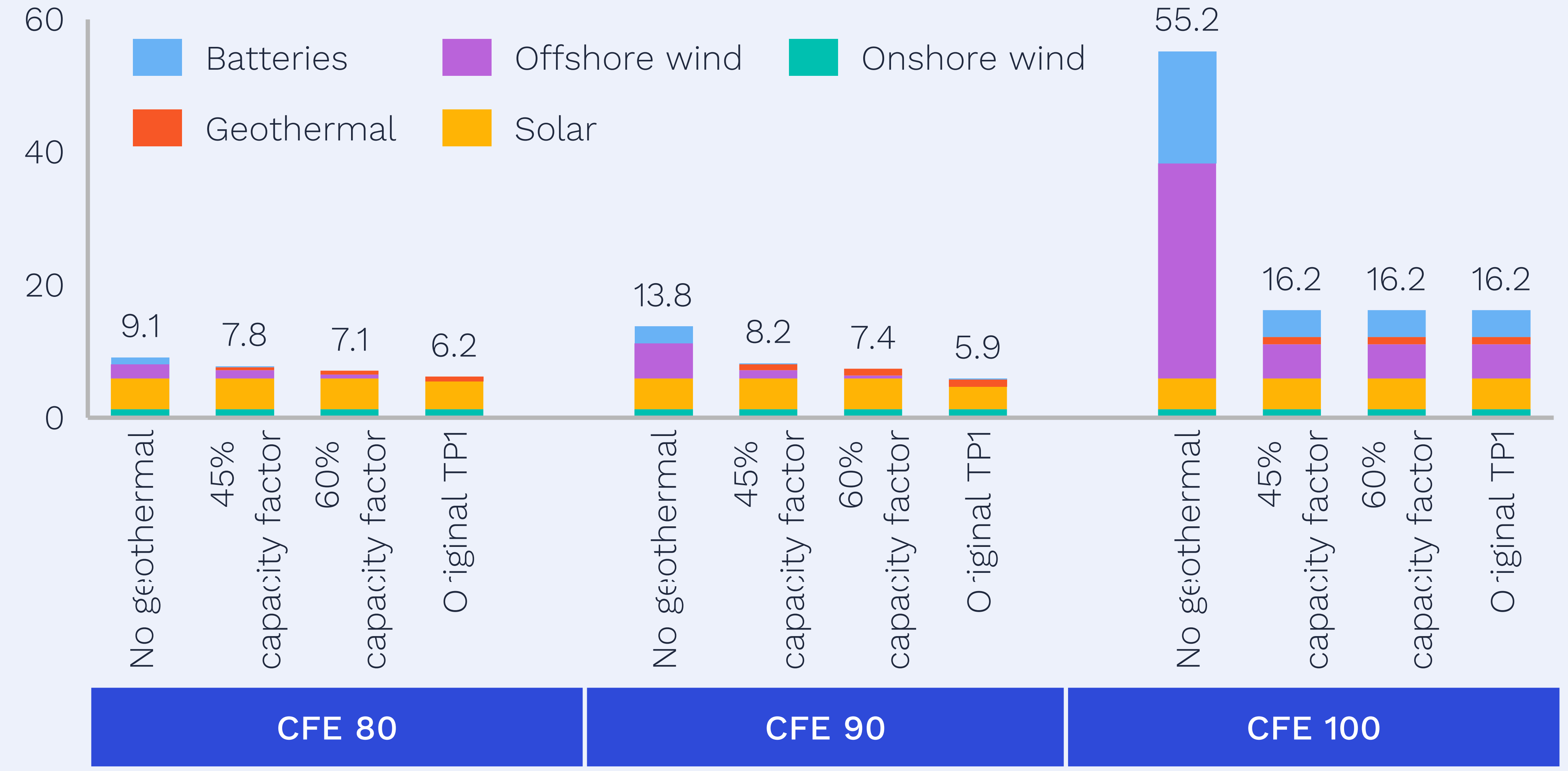
The ability to dispatch geothermal at high-capacity factors radically reshapes the capacity mix under hourly matching scenarios

1. **Including geothermal helps avoid the drastic offshore wind buildout seen at CFE 100.** In a sensitivity test to assess the contribution of geothermal, we decided to exclude it from TP1, and we also removed the offshore wind build constraint to keep the model feasible. The result shows that without geothermal, achieving CFE 100 would require more than a fourfold increase in offshore wind capacity and over a sixfold increase in batteries. Similarly at lower CFE scores, removing geothermal not only forces solar to hit its build limits to close the gap but also triggers previously absent offshore wind to be built (2.2 –5.3 GW in the no-geothermal case) and increases batteries uptake (0-124 MW in original TP1 vs 1,032-2,555 MW in no-geothermal case).
2. **Offshore wind is in direct competition with geothermal at lower CFE scores.** Beyond the exclusion test in TP1, we also varied the capacity factor of geothermal from the 75% assumed in TP1 down to 45% in 15 percentage-point increments, keeping the same build constraint. At CFE 100, the capacity mix remains unchanged, indicating that even with a geothermal capacity factor as low as 45%, the system still has enough CFE generation and storage to meet demand. The picture changes at lower CFE scores: once the capacity factor falls to 60%, geothermal uptake declines, and offshore wind fills the gap. This suggests that at capacity factors above 60% threshold, geothermal effectively outcompetes offshore wind.
3. **Without investment in geothermal, PPA offtakers would face nearly five times higher unit costs at the highest CFE levels, erasing any cost competitiveness against electricity tariffs**. At CFE 100, where significant overbuild occurs, we do not see the expected increase in PPA sales to the grid. This is because the model applies a maximum sales constraint set to a very generous 100% of C&I load, which forces PPA assets to curtail surplus CFE beyond the cap, preventing them from offsetting their high CAPEX.
4. **Geothermal utilisation has a direct impact on PPA unit costs.** As the capacity factor declines, PPA costs rise because each MW of installed capacity produces less CFE on a yearly basis, reducing its economic value. In other words, consumers pay more for every MWh generated.

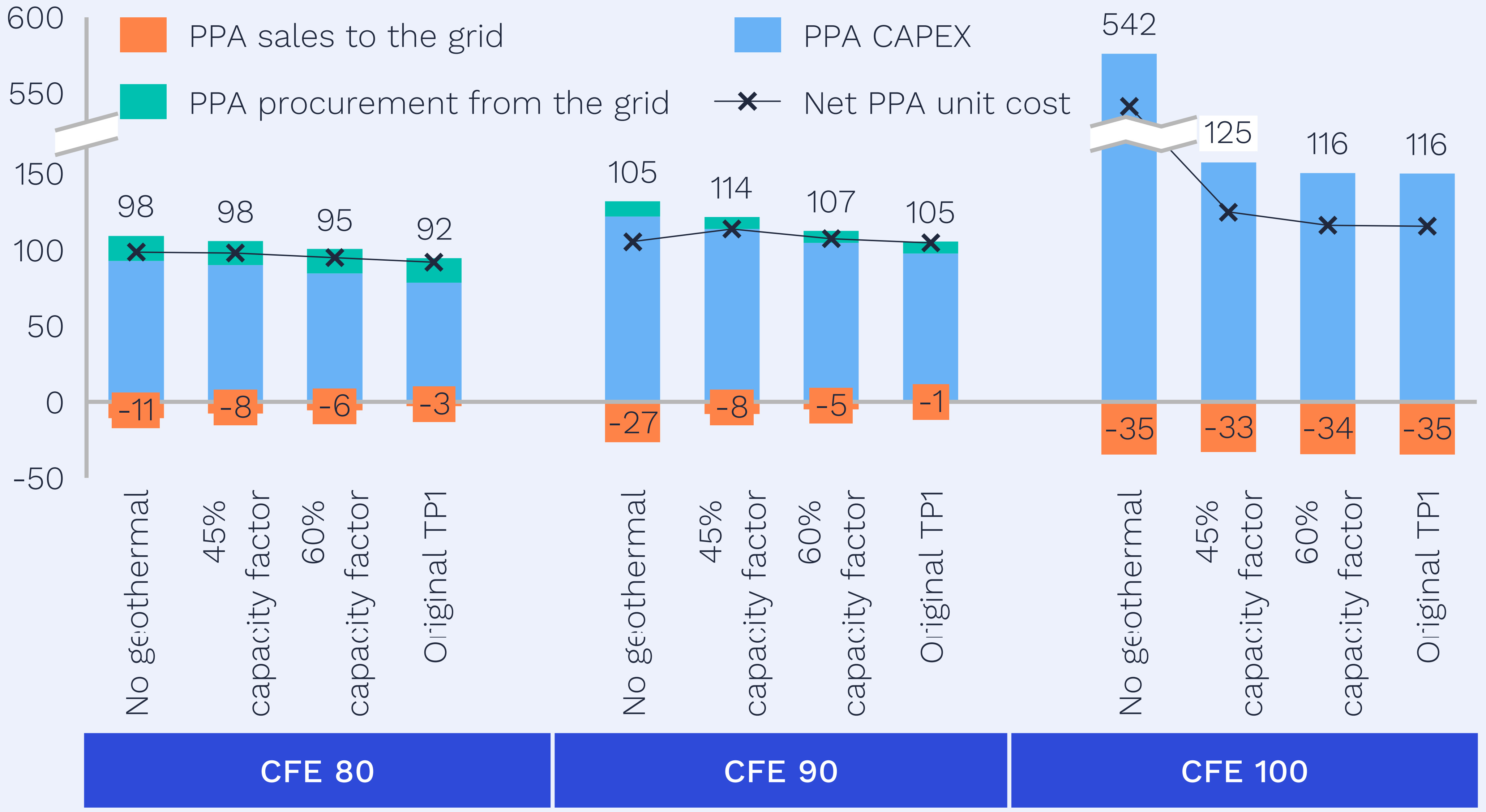
[1] We exclude the annual matching scenario from this discussion, as geothermal is absent from the original TP1 even with a 75% capacity factor
[2] CAPEX figures shown are expressed in real 2023 money base and annualised, based on the assumed lifetime of individual assets and discounted to present value..

Geothermal and offshore wind uptake (GW)

Projected capacity is sensitive to assumptions ...



PPA unit costs (USD/MWh)



Source: TZ modelling.

Technology risk 2: Offshore wind

The mismatch between offshore wind lulls and Taiwan's summertime demand peaks drives up the expansion needs at CFE 100

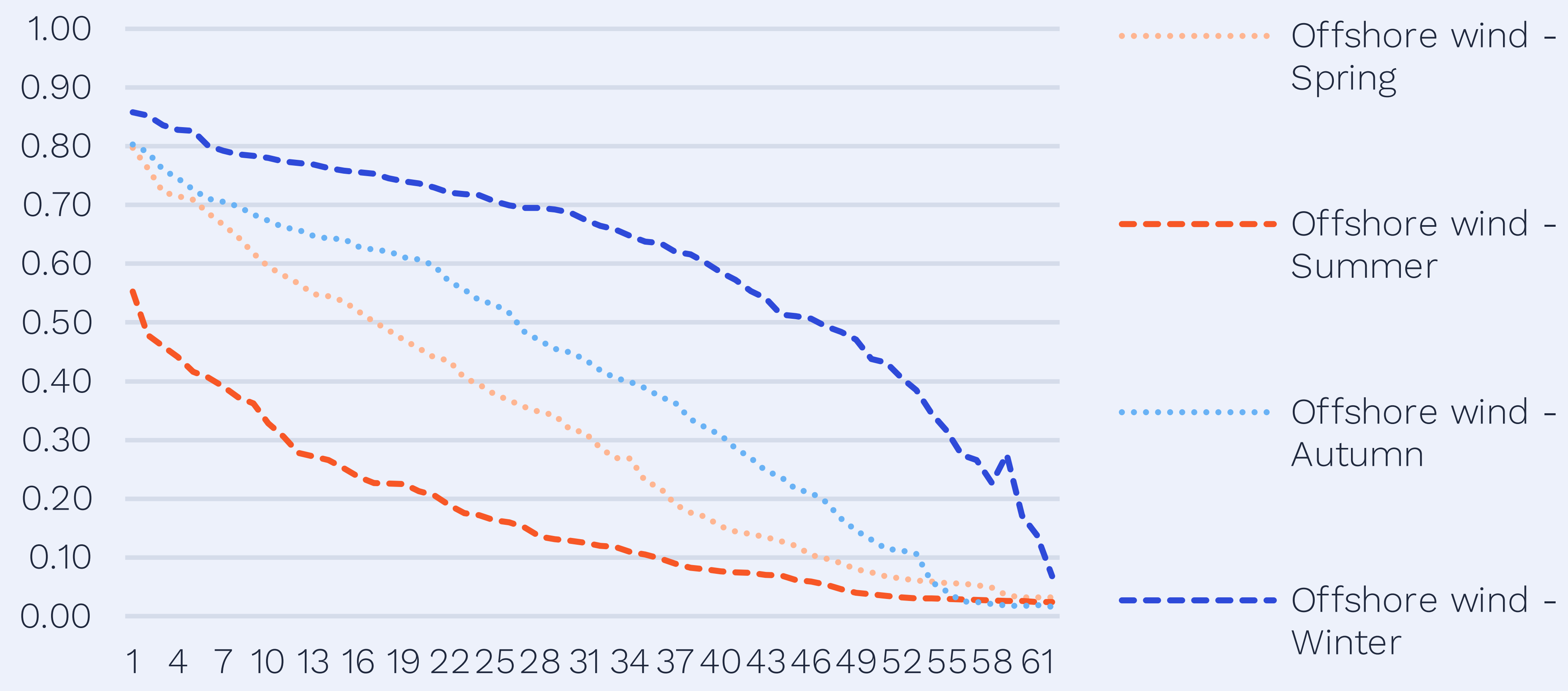
1. **Seasonal variability drives exponential expansion at the highest CFE score.** In TP1, moving from CFE 99 to CFE 100 requires material oversizing of the PPA capacity mix, rising from 10.1 GW to 16.3 GW, with an additional 4.1 GW of offshore wind (1.1 GW at CFE 99) and 2.0 GW of batteries (2.0 GW at CFE 99) added to decarbonise just the final few hours. This oversizing is caused by the pronounced seasonal variability of offshore wind in Taiwan. With all other technologies already maxed out, offshore wind becomes the only option to cover the remaining low-renewable hours. Averaging capacity factors for offshore wind over 12 hours[1] and ordering the resulting buckets in descending order across representative average month of each season shows that the output of offshore wind peaks in winter but drops in summer, precisely when Taiwan's electricity demand is highest. This mismatch forces the system to oversize offshore wind and batteries to cover those hours despite the costliness. This must happen because procurement from the carbon-heavy grid can't bridge generation gaps, and limited 6-hour battery windows reduce the effectiveness of charging. However, the scale of the impact shown on the previous slide may vary with different weather year selections.
2. **In TP2 long-duration storage avoids the excessive buildout of offshore wind and batteries.** With its much longer operating window, LAES can store surplus CFE during high-generation periods and time-shift it more effectively to cover offshore wind lulls, even at CFE 100. Compared with TP1, the addition of 1.1 GW of LAES reduces offshore wind capacity by 76%, from 5.1 GW in TP1 to just 1.2 GW, only 100 MW more than at CFE 99 in TP1. Furthermore, LAES also actually reduces the required batteries capacity from 2.0 GW at CFE 99 down to just 1.1 GW.

[1] *Bucketing range selected to exceed the storage duration of a 6h battery system.*

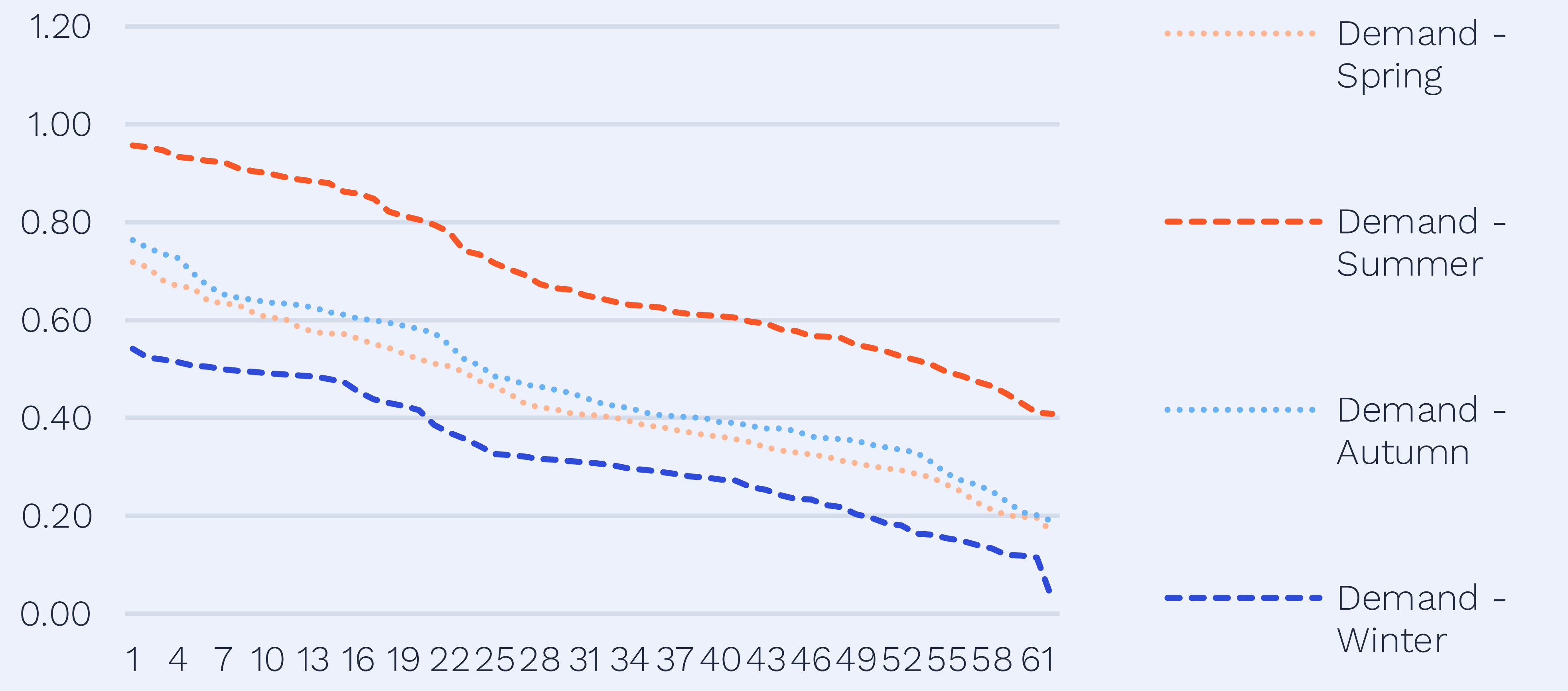
Source: TZ modelling.

Ordered offshore wind capacity factors and ordered normalised demand, averaged across 12-hour intervals[1]

Offshore wind experiences its seasonal lulls during summer…



… causing a mismatch with the period when electricity demand in Taiwan peaks



Technology risk 3: Carbon Capture and Storage

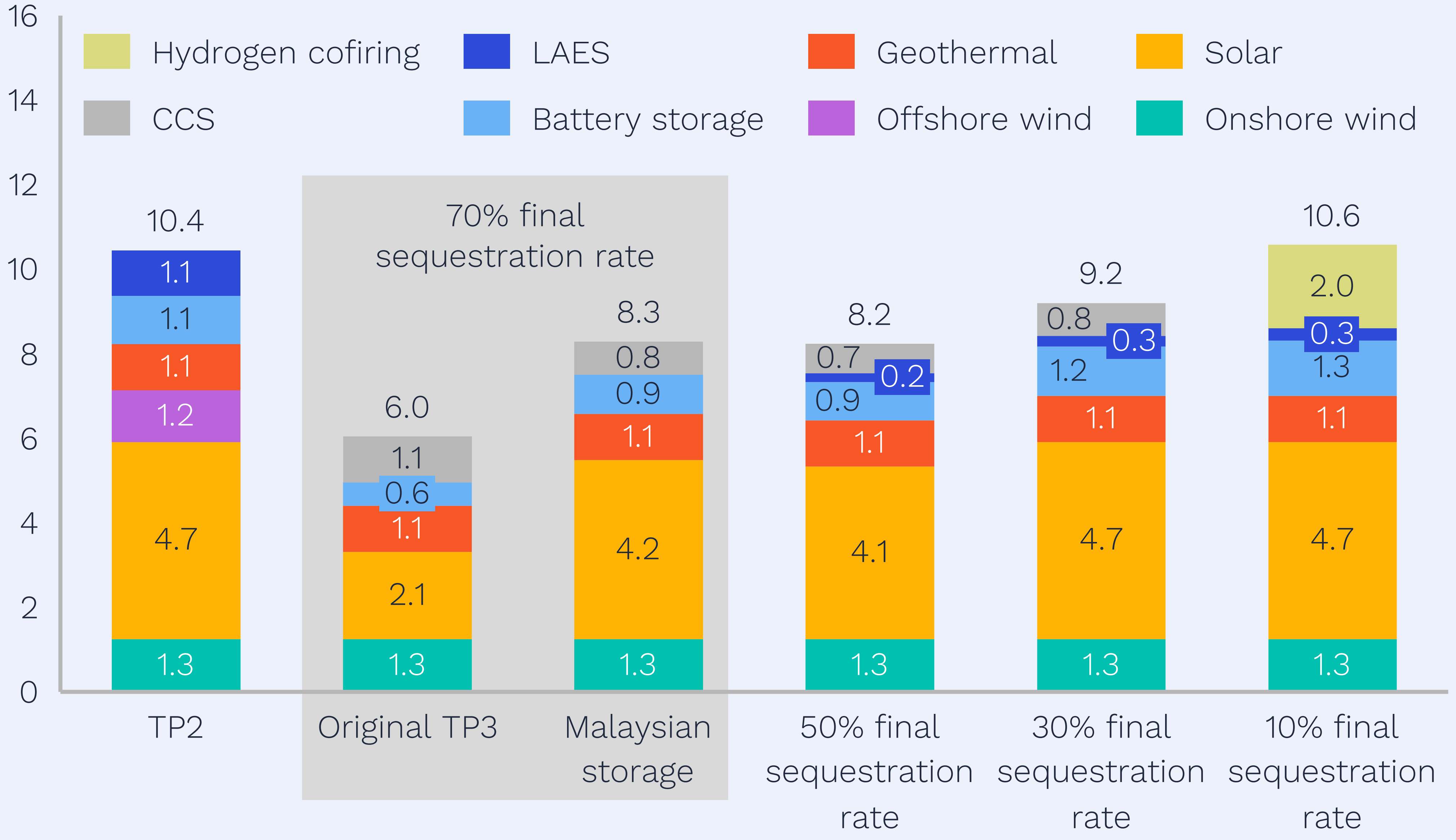
Our sensitivity analysis shows that several factors radically alter the role of CSS under the CFE 100 scenario

1. **CCS uptake is particularly sensitive to two variables: final sequestration rates[1], and storage and transportation costs.** We have conducted sensitivity analysis against our standard TP3 assumptions whereby 70% of all CO_2 caused by electricity generation is permanently stored underground, and the storage site is located in the Taiwan straits, on average around 100-200 km away from all potential CCS plant sites.[2]
2. **Even with a low capture rate, CCS is preferred over offshore wind. Lower capture rates reduce CCS's cost competitiveness, as each MWh delivers less net CFE for hourly matching.** As capture rates fall from 70% to 50%, solar and storage uptake rises to compensate, nearly doubling from 2.1 GW to 4.1 GW. When capture rates drop to 30%, solar reaches its build limit. With more renewables in the mix, storage expands accordingly — batteries first, but also LAES once the capture rate falls to 50% or lower.
3. **CCS is adopted only when the final sequestration rate exceeds 10%. Below this threshold, CCS loses its cost competitiveness and uptake is nil.** When the CCS capture rate reaches the same level as the blend ratio of hydrogen co-firing, co-firing completely replaces CCS. This indicates that, under our assumed 1:9 hydrogen-to-gas energy blend, co-firing produces CFE more cost-effectively than CCS.
4. **Even without local CO_2, CSS has a role to play.** We decided to explore what might happen if carbon capture facilities were built outside of Taiwan, for example in Malaysia, mirroring Memoranda of Understanding signed between the Malaysian and Japanese governments. This results in an average shipping distance of 2,500 km from Taiwan central region to Bintulu, Sarawak. Under these conditions, CCS is still competitive enough to see build-out despite seeing a reduction of 27% relative to the original TP3 capacity. Solar and batteries compensate for the lost capacity.
5. **Offshore wind is not attractive when it has to compete with a dispatchable CFE source.** Even at a 30% final sequestration rate the model retains around 0.8 GW of CCS and no offshore wind, suggesting it's still cheaper to dispatch highly 'carbon leaky' CCS over investing in offshore wind. Even when hydrogen cofiring replaces CCS, CFE from offshore wind is still too expensive and unreliable to come into the picture. This result may change if a different weather year were utilised.
6. **System-wide emission savings with CCS are dented relative to TP2.** As CCS expands, renewable capacity decreases, leading to less excess clean generation and therefore less impact on the activity of thermal plants on the grid. In addition, because CCS is leaky, the more it is used, the greater the residual emissions from the plant itself.

[1] Defined as the capture rate of CO_2 resulting from fuel combustion, times the sequestration rate for the captured CO_2.
[2] The only current CCS testing site is located at Taichung which is along the central coast. Its coastal location makes it accessible by pipeline, and importantly, all future potential convertible gas-fired power plants are also situated along the coast supporting the feasibility of a connected CCS pipeline infrastructure.
[3] Greenfield emissions refer to the leaked emissions when innovative thermal is being utilised.

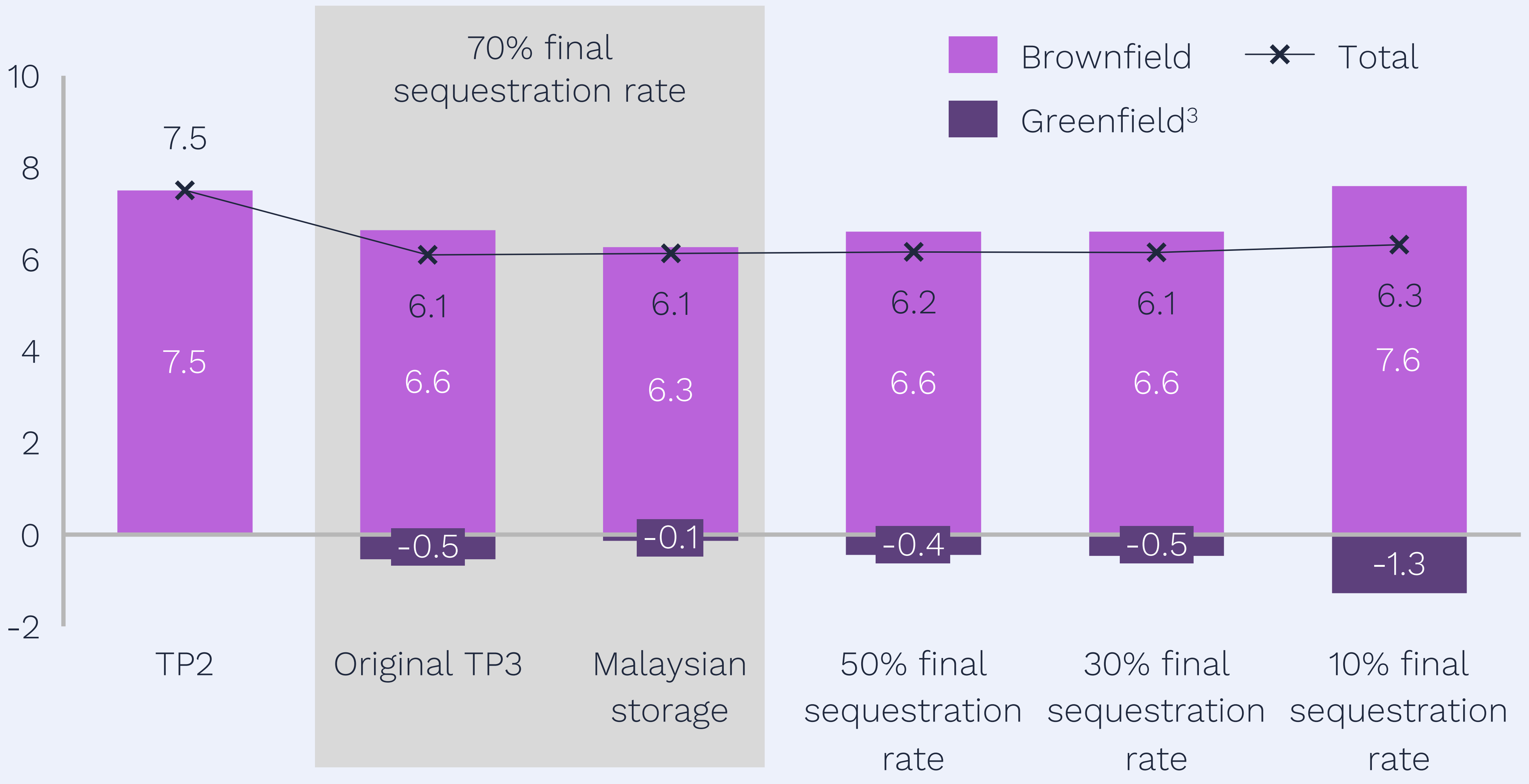
CCS and LAES uptake (GW)

Projected capacity is sensitive to assumptions …



National emissions impact ($MtCO_2e$)

… and leaks affect its emission impact



Source: TZ modelling.

Summary of policy sensitivities

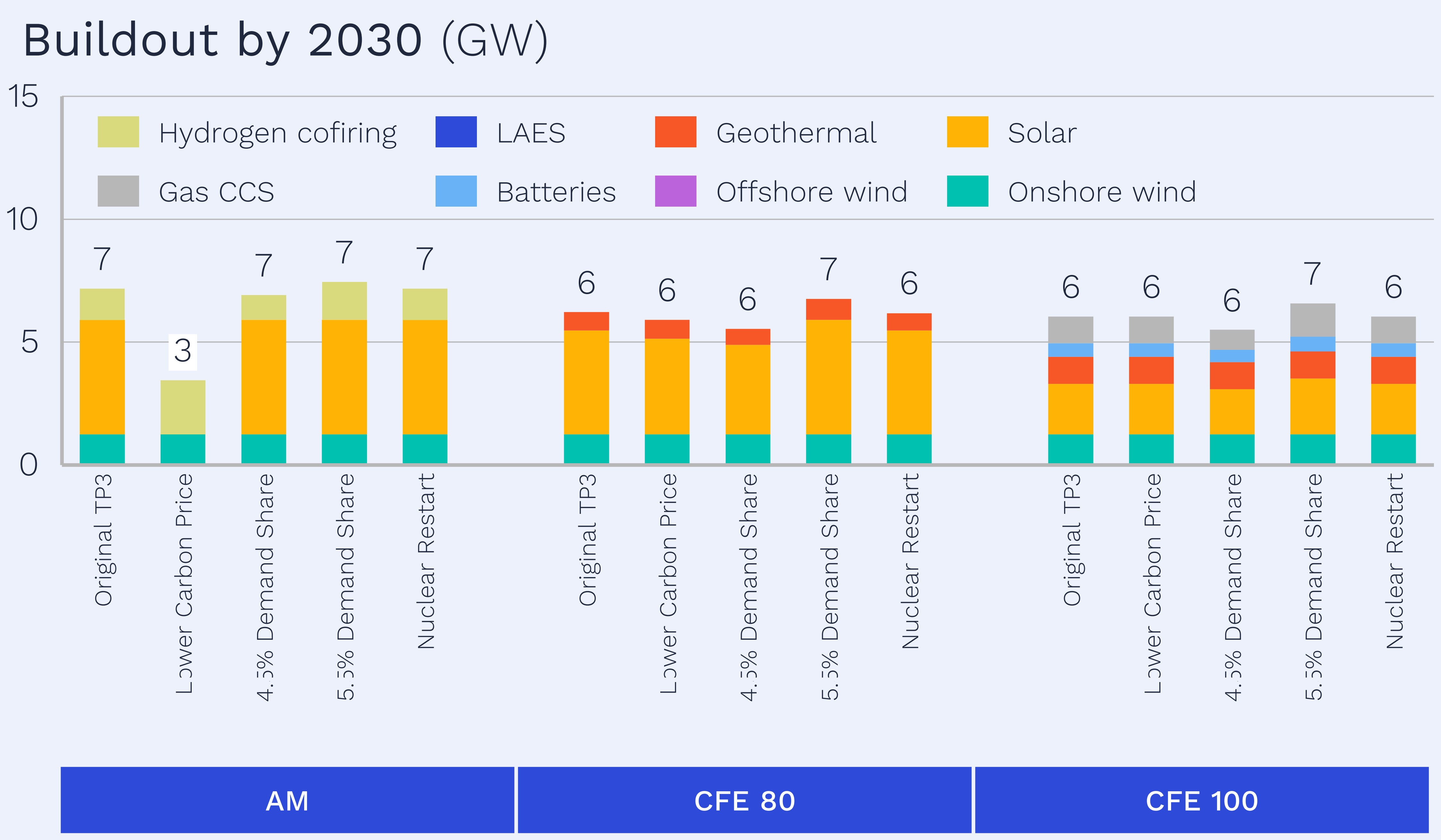
Using the broadest technology palette as the base scenario, we also examined three key input assumptions which are subject to the greatest uncertainties

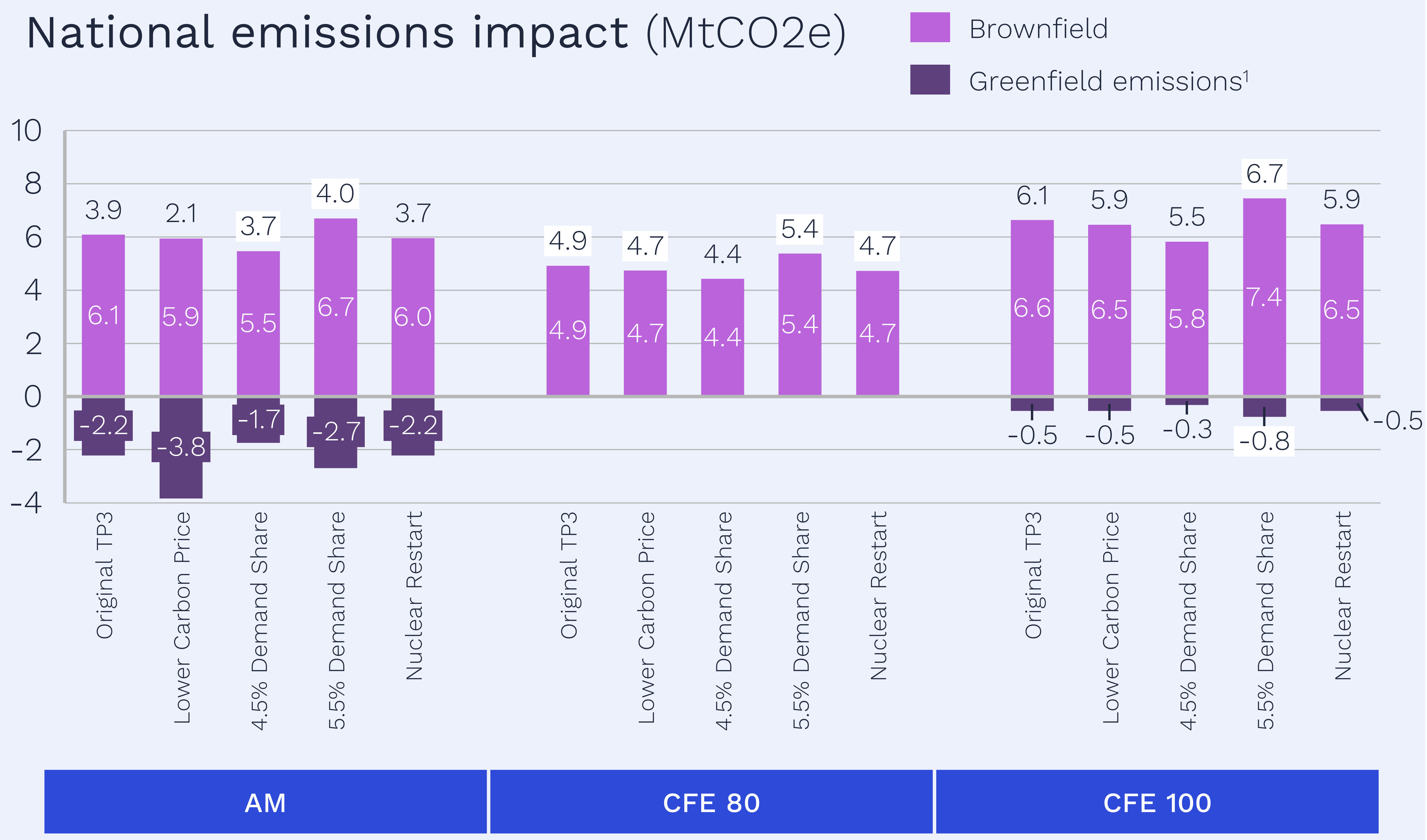
Scenario	Definition
Nuclear restart	Following the recent public memorandum on the potential restart of Nuclear Plant #3 in Taiwan, we assumed its successful restart for exploratory purposes, adding 1,905 MW of nuclear capacity in our 2030 brownfield capacity mix.
C&I demand share	In response to interest from multiple local Taiwanese experts regarding the impact of varying demand levels, we conducted two sensitivity analyses assuming 2030 C&I electricity demand 10% higher and 10% lower than our original baseline input.
Carbon price	We explored a scenario in which that carbon prices remain stagnant at NT$300 (US$9) from 2025 to 2030, instead of rising to NT$1,200 as in our base case (which is the lower end of the Taiwanese government’s proposed 2030 range of NT$1,200–1,800 (US$37–56)).

Assessing input and assumption risk (1/2)

We tested some of the most controversial inputs and assumptions to quantify their influence on model outcomes under TP3

1. **Lower carbon prices boost the cost-competitiveness of innovative thermal generation.** In our base case, we follow the Taiwanese government's proposal to gradually increase the carbon price from US$9 (NT$ 300) in 2025 to US$37 (NT$ 1,200) in 2030. However, if prices remain flat through 2030, renewable capacity falls under annual matching and CFE 80. Under annual matching, solar is displaced entirely by more cost-competitive hydrogen gas co-firing. This is because the lowered carbon price reduces the cost of hydrogen co-firing, making it cheaper to redirect all the funds used to build solar under our regular TP3 scenario to expand co-firing capacity by 42% in the sensitivity. However this change in the capacity mix comes at the cost of reduced emissions savings. For CFE 80, solar uptake falls slightly by around 8% against a simultaneous expansion of geothermal by around 3%. This is because under a lower carbon prices, coal becomes cheaper than gas to dispatch, reducing greenfield sellback opportunities as the coal-heavy brownfield becomes less flexible and can't accommodate as much sellback. By contrast, at CFE 100, no notable changes are observed.
2. **C&I demand share alters the overall capacity mix, with different impacts under different matching regimes.** Under annual matching, where supply reliability is less critical, changes in C&I demand affect only hydrogen co-firing, the least cost-competitive technology. Under hourly matching, however, the system weighs both cost and reliability when adjusting capacity. This is why geothermal is affected at CFE 80 and CCS at CFE 100, in addition to the least reliable solar. Nevertheless, system-wide emissions scale proportionally with changes in C&I demand.
3. **In the nuclear restart sensitivity case, no noticeable effects are observed on outcomes**. At CFE 80, geothermal uptake falls slightly, by about 6%, from 741 MW to 699 MW, because restarting nuclear marginally raises the brownfield CFE score, allowing more procurement from brownfield into greenfield. As the system moves toward CFE 100, the effect disappears since no procurement is permitted from the brownfield, due to the presence of unabated thermal generators. As expected, there is no difference between the original TP3 and the nuclear restart case under annual matching, where the absence of an hourly constraint means the model does not optimise for grid procurement.





¹ Greenfield emissions refer to the leaked emissions when innovative thermal is being utilised.

Source: TZ modelling.

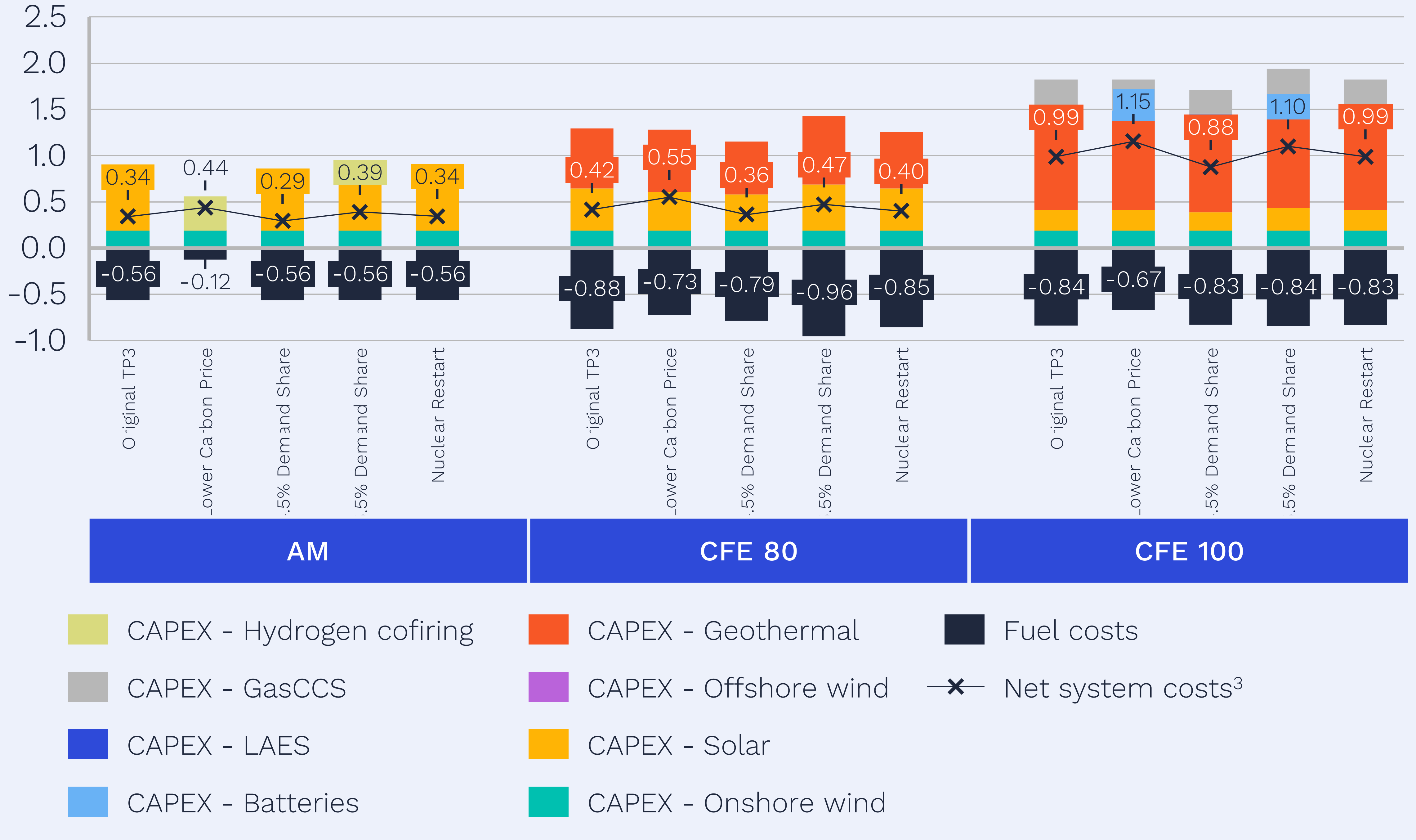
Assessing input and assumption risk (2/2)

Carbon price swings can reshape dispatch economics and shift the entire cost structure

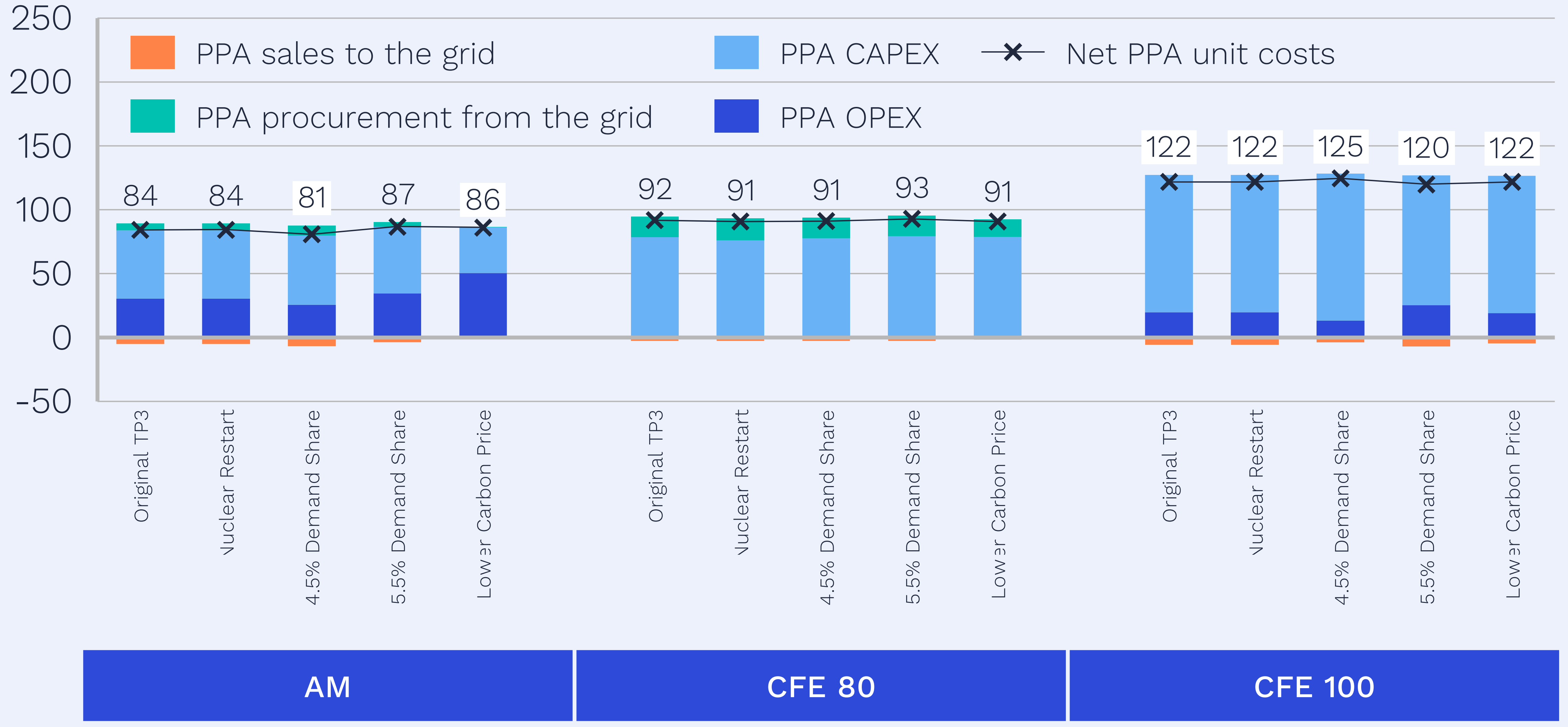
1. **Lower carbon pricing drives up the total system costs.** If carbon prices remain flat through 2030, annual matching shifts investment away from solar toward gas–hydrogen co-firing. With its higher capacity factor, this lowers CAPEX by 38% compared to the original TP3. However, fewer renewables in the system mean fewer CFE sales from the greenfield, reducing the displacement of marginal brownfield generators. This cuts fuel cost savings, leaving net system costs higher than in original TP3. Under hourly matching, renewables remain a significant part of the mix, but the lower carbon price reduces the marginal cost of thermal generation in the brownfield. As a result, fuel savings from surplus CFE sales decline, while significant CAPEX is still required to meet hourly matching goals – thus pushing up net system costs.
2. **Changes to the share of the participating C&I demand has the largest impacts to the cost structure.** Changing C&I demand moves total system costs in the expected direction. While greater PPA sales back to the brownfield deliver fuel savings that partially offset additional investment, the effect is limited – and vice-versa. The observed pattern applies to PPA unit costs as well under annual matching and CFE 80. At CFE 100, however, the relationship with PPA unit costs inverts: higher demand lowers the unit cost, and lower demand raises it. This is because at CFE 100 the system must already overbuild materially to cover the final low-renewable hours, creating a large fixed cost. When demand increases, that cost is spread across more consumption, reducing the average PPA unit cost, whereas lower demand concentrates the same burden over fewer MWh, driving it up.
3. **Nuclear restart has minimal impact on total system costs or PPA unit costs.** At 100% hourly matching, the effect is zero because grid procurement is not permitted. Under annual matching, the impact is also negligible since the looser annual constraint does not require hourly balancing, and the model therefore does not optimise around grid procurements.

[1] *These comprise all capital, operational, and fuel expenditure of the entire system, including PPA assets.*
[2] *CAPEX figures shown are expressed in real 2023 money base and annualised, based on the assumed lifetime of individual assets and discounted to present value.*
[3] Net system costs are calculated from the sum of CAPEX paid by the C&I consumer and fuel cost savings to the grid.

System-wide costs and benefits[1,2] (Billion USD)



PPA unit costs (USD/MWh)



Source: TZ modelling.

Annex

Further information, data and assumptions

Glossary (1/2)

Term	Definition
Brownfield generators	Total CFE and non-CFE capacity mix forming the basis of our Reference Scenario, required by 2030 to meet overall electricity demand, resulting from a mixture of present capacity and new-build to account for variations in demand, retirements of current plants, and restart of idled plants
Brownfield procurement	CFE procured by C&I consumers from brownfield generators from the same grid zone when contracted same-zone greenfield generators are insufficient to cover CFE demand
C&I	Commercial and Industry
CFE	Carbon-free electricity, including renewables, nuclear power, the emission-free part of innovative thermal plants, and electricity discharging from storage technologies [after being charged up from generation from the previous categories]
Consumer CFE score	Hourly share of CFE from a consumers' total electricity consumption, resulting from both greenfield and brownfield procurement
Grid CFE score	Hourly share of CFE within all brownfield generation from a single grid zone

Glossary (2/2)

Term	Definition
Grid zones	The five regional grid zones in India, i.e. India North, India South, India East, India West, and India North-East.
Imports	Flows across interconnectors from adjoining grid zones to satisfy demand for electricity generally or CFE specifically
Innovative thermal	Thermal plants that are either equipped carbon capture (capacity adjusted for leakage) or are co-firing fuels deemed to emit no CO2 at the point of combustion (hydrogen, ammonia, biomass)
Interconnector	Transmission-level power cables connecting two countries or two grid zones within a country
Matching regime	Modelling constraint forcing C&I consumers to reach a specified CFE score, matched either against total annual consumption or across each hour of the year
Palette	Scenario-specific combination of technologies deemed eligible for CFE status

Tech build constraints

We seek to impose sensible limits on what type of capacity expansion we allow in the Reference Scenario

Tech name	Planned new-build	Modelled additional build
Coal	✗	✗
Oil	✗	✗
Gas	✓	✓
Biomass – solid	✓	✓
Solar	✓	✓
Hydro	✓	✗
Pumped hydro	✗	✗
Nuclear	✗	✗

Tech name	Planned new-build	Modelled additional build
Ocean	✗	✗
Offshore wind	✓	✗
Onshore wind	✓	✓
Batteries	✓	✓
Green/Blue H2	✗	✗
Gas CCS	✗	✗
Cogeneration – coal	✗	✗
Cogeneration - biogas & waste	✗	✗

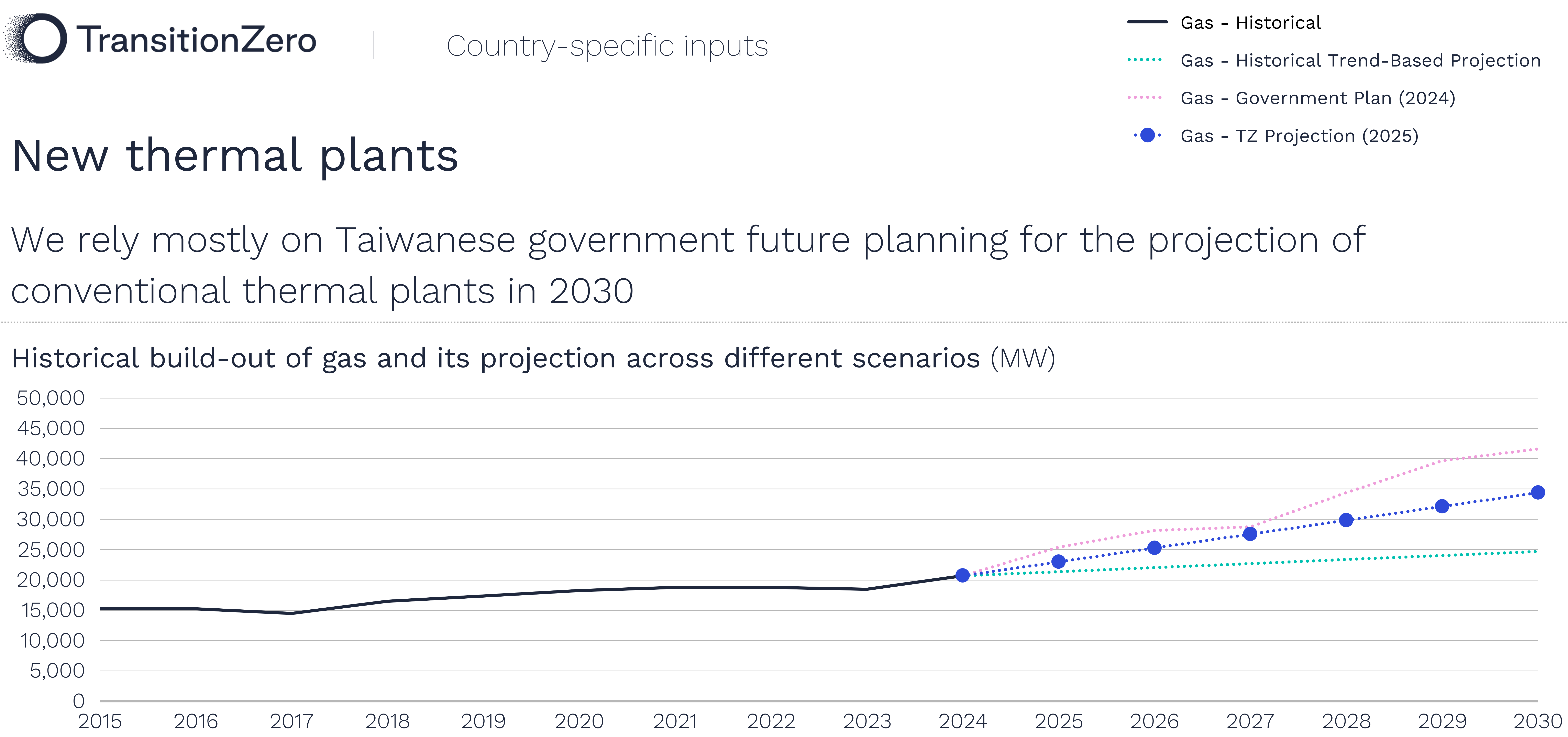
Notes

- To align with Taiwan's policy landscape and ambitions, we exclude all nuclear and fossil-fuel power plants except for gas-fired plants.
- We reflect an expected expansion of small-scale hydro.
- We do not model new pumped hydro capacity, either exogenously or endogenously, as recent developments are expected to come online only after 2030.
- For ocean energy, we disallow both exogenous and endogenous new builds due to the technology's low readiness and limited real-world deployment.
- We allow planned and announced new capacity for offshore wind to reflect licensed wind farms expected by 2030 – but due to siting limitations and long project lead times we do not allow the model to build endogenously new capacity.
- We do not allow additional capacity for thermal co-firing and CCS exogenously on the brownfield as they are still in experimental phase but do allow the model to build further capacity endogenously under our CFE exploratory scenario analysis as part of the tech palette 3.
- We acknowledge that qualified cogeneration plants in Taiwan — primarily for self-consumption — are permitted to export surplus electricity to the grid. However, we do not model any expansion of such plants, as their primary role is to meet on-site needs, and their output to grid is highly inconsistent.

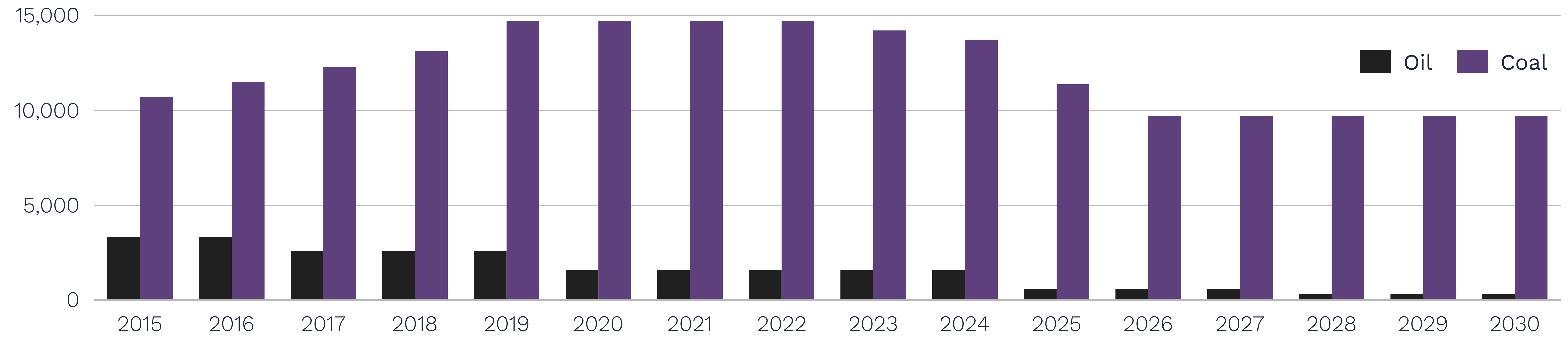
New thermal plants

We rely mostly on Taiwanese government future planning for the projection of conventional thermal plants in 2030

Historical build-out of gas and its projection across different scenarios (MW)



Historical build-out of oil and coal and its projection (MW)

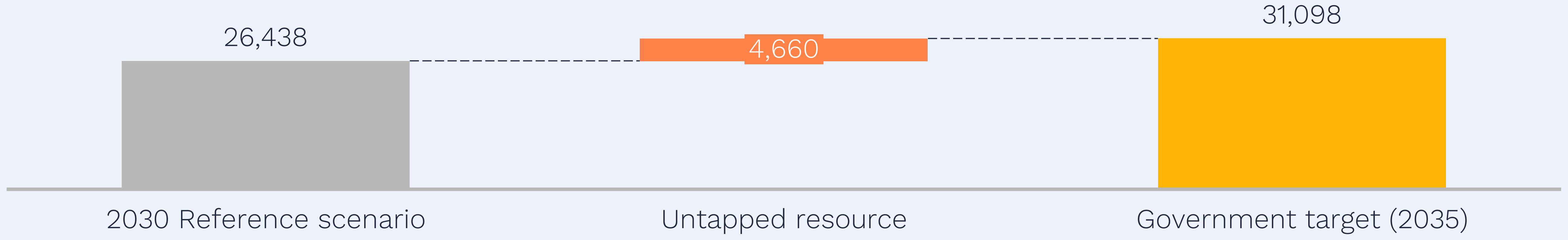
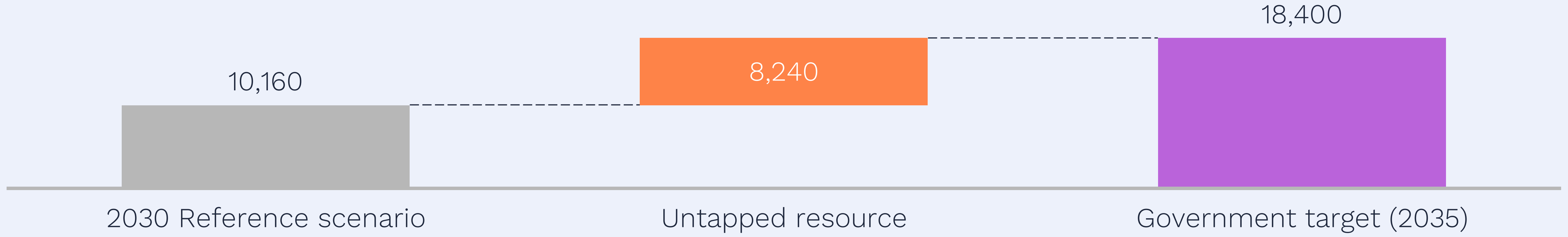


Notes

- For thermal exogenous capacities, we refer to the future power supply plan outlined in the 2023 National Power Resources Supply and Demand Report. Based on this, we calculate the planned annual additions and retirements of plants, as well as the corresponding active generation fleet through 2030.
- We note the government's official plans for coal and oil-fired power plants without modification. However, for gas-fired capacity projections, we have taken a more conservative approach by delaying the target timeline by two years. As a result, the 2028 government target is now assumed to be met in 2030. This adjustment is informed by the historical commissioning rates of gas power plants, observed delays between planned and actual commissioning dates, and recent challenges identified in IPP auction processes.

Greenfield renewable build constraints

We set realistic limits on the maximum capacity expansion for each technology

Technology	Maximum new capacity allowed (MW)		Description
Onshore wind	1,250		Untapped resource for onshore wind is set equal to the total secondary site potential by 2035, as estimated by the Taiwan 2050 Calculator[1].
Solar	4,660		For solar, offshore wind, and geothermal, we draw on the decarbonisation actions plan[2] released by MOEA in early 2025. Untapped resources are defined as the difference between the capacity in the reference scenario and the government's 2035 build targets. For solar, only ground-mounted utility-scale projects are considered.
Offshore wind	8,240		
Geothermal	1,097		

[1] *Taiwan 2050 Calculator report version. Online calculator is no longer available, but summary report is still accessible (August 2025).*
[2] *Decarbonisation Actions of Energy Department (2025)*

Greenfield capacity factor constraints

We model intermittent renewables using profiles with hourly granularity, whereas dispatchable technologies are allowed to float up to their maximum yearly capacity factor constraints

Technology	Annual average of hourly profile (%)	Description
Solar	13	We employ 8,760-hour capacity factor profile for solar, onshore wind, and offshore wind across both greenfield and brownfield to account for their intermittent and seasonal nature. These profiles are constructed from historical generation data provided by ElectricityMaps, and for wind specifically, from the Taiwan Department of Energy's Tableau Dashboard[1]. Both are derived from Taipower's official 10-minute interval reporting[2].
Onshore wind	27	
Offshore wind	38	

Technology	Maximum capacity factor constraint (%)	Description
Geothermal	75	Stakeholder input and Taipower data[2] suggest current geothermal facilities in Taiwan operate at ~45% capacity factor. However, desk research shows binary-cycle plants, Taiwan's dominant type, have reached 75–80% in other jurisdictions, matching accounts of performance at facilities for which contacts have been recently signed.
Gas CCS	66	We apply maximum annual utilisation constraints on gas CCS and gas–hydrogen co-firing plants, based on the historical five-year average of mean annual utilisation rates. We derived these rates using hourly data sourced from ElectricityMaps on gas-fired power plants, to account for operational factors such as outages and must-run conditions.
Gas-hydrogen co-firing		

[1] Taiwan Department of Energy's Tableau Dashboard
[2] Taipower official website

New renewable plants

We impose realistic build constraints for 2030

Notes

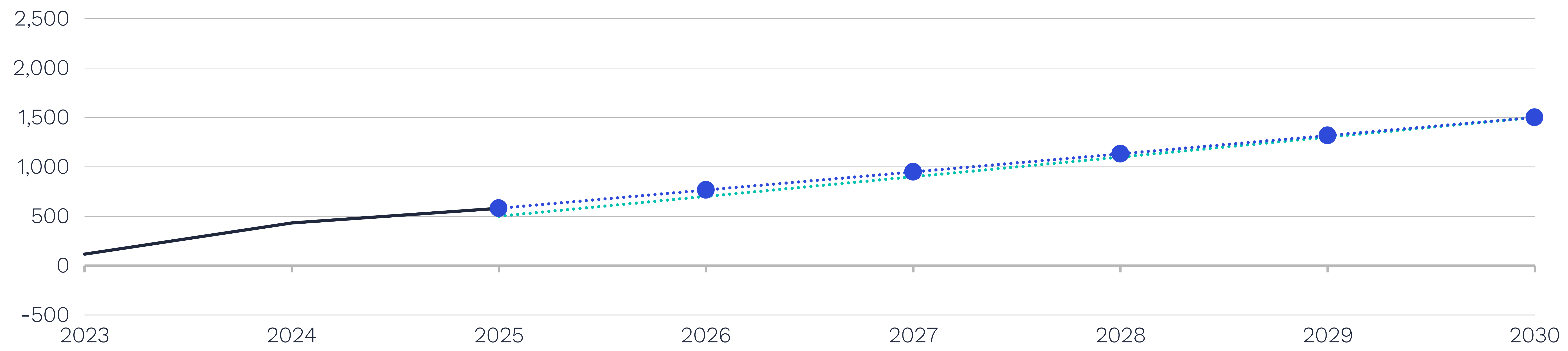
- We analysed the historical build rates of each technology and compared them with multiple iterations of government targets to assess their feasibility. Where targets appeared overly ambitious, we adjusted them downward to produce more conservative and realistic projections.
- For solar, we used the historical 5-year average commissioning rate as the basis for projecting future buildout to 2030. This is in contrast to government targets announced in 2023 and 2025, which we consider overly ambitious — particularly the 2025 target that assumes a 6 GW rollout in a single year.
- We acknowledged the significant progress made in offshore wind under government policy and recognised that its buildout is largely policy-driven. Given that long-term historical build rates may not reflect future trends, we instead used the most recent and highest single-year build rate — that of 2024 — as the expected commissioning benchmark. The final projection aligns closely with the updated 2025 government target.
- In the case of geothermal, the latest government projections differ substantially from both earlier targets and historical trends. Based on this discrepancy, we adopted a more conservative build rate — exactly half of the most recent government's planned figure — to better reflect what is likely to be commissioned by 2030
- We applied the same methodology and adjustment logic to all other renewable technologies to ensure consistent projections.
- It also worth noting that we apply the adjustment at the aggregated level rather than at individual asset level. In future work, we plan to explore a bottom-up approach using asset-level data.

New storage

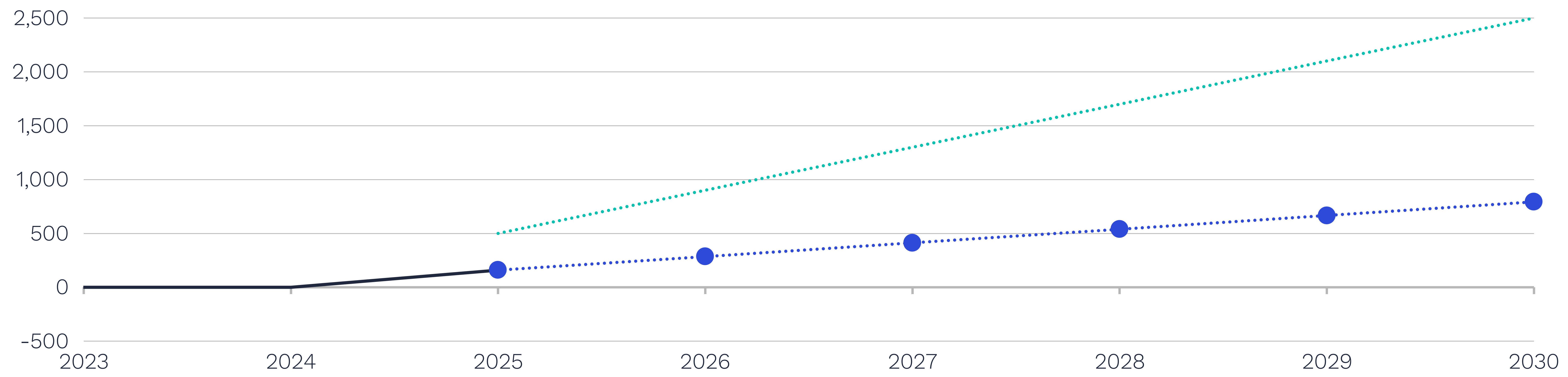
We impose realistic build constraints for 2030

Historical
Government Target (2023)
TZ Projection (2025)

Historical build-out of demand shifting (E-dReg[1]) batteries and its projection (MW)



Historical build-out of solar hybrid batteries and its projection (MW)



Notes

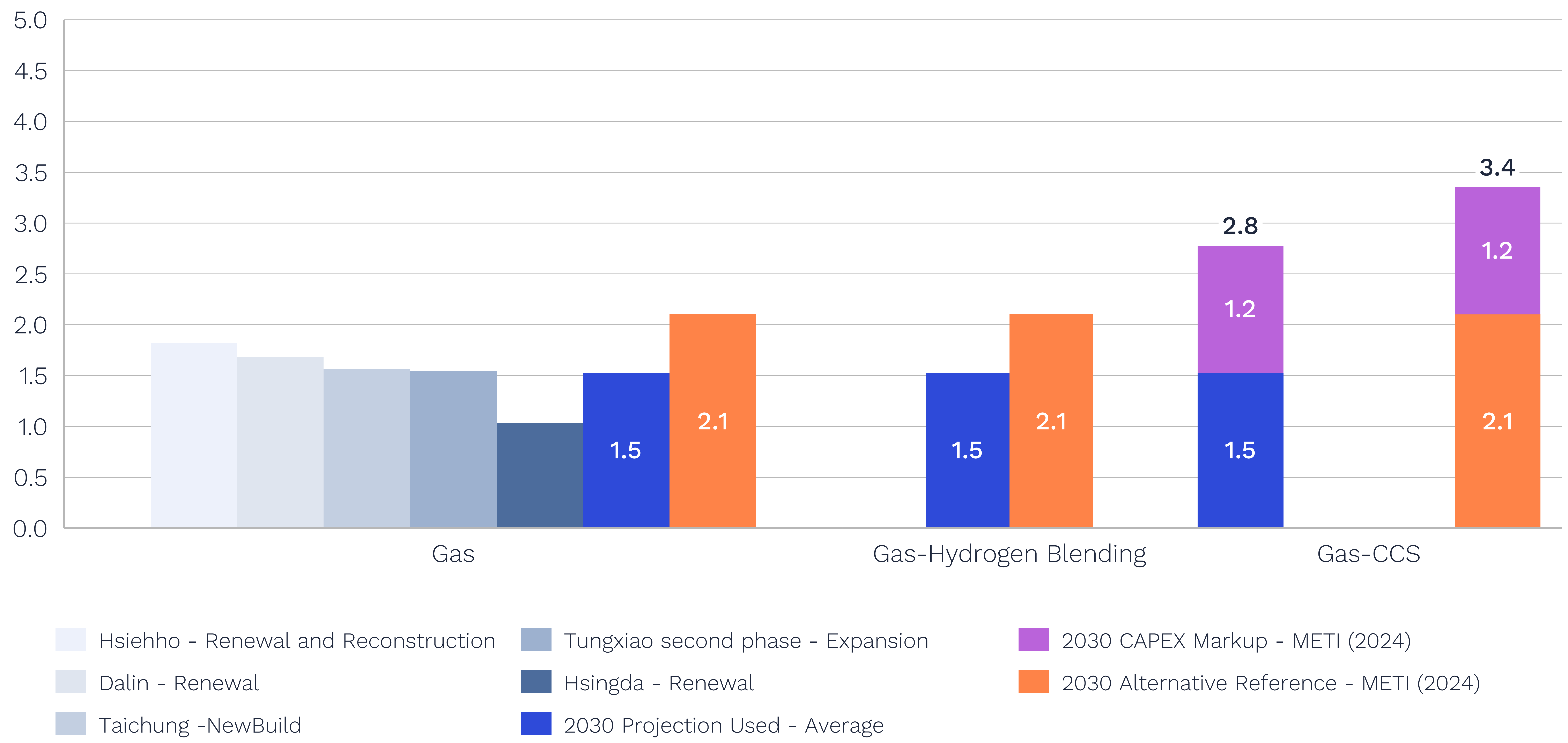
- We only include batteries that contribute to demand shifting — such as solar hybrid systems or those participating in E-dReg[1] — while excluding batteries primarily optimized for frequency regulation (e.g., sReg/dReg), which are designed to serve ancillary service functions rather than influence net demand.
- We adopted the government's target capacity for demand-shifting batteries, as the historical build-out rate has met or even exceeded the official targets.
- For solar hybrid batteries, we reduced the government target by 68%, given that historical deployment — based on our desk research — has been relatively limited.

[1] *E-dReg stands for Enhanced Dynamic Regulation in Taiwan's ancillary services market. It is a fast-response, high-resolution grid balancing service designed by Taiwan Power Company (Taipower) to support real-time frequency regulation and net demand stabilization*

Gas power plant characteristics

We reviewed the costs of the most recent gas power plant developments reported by Taipower

CAPEXes reported across different latest gas plant developments and different sources (million US$/MW)



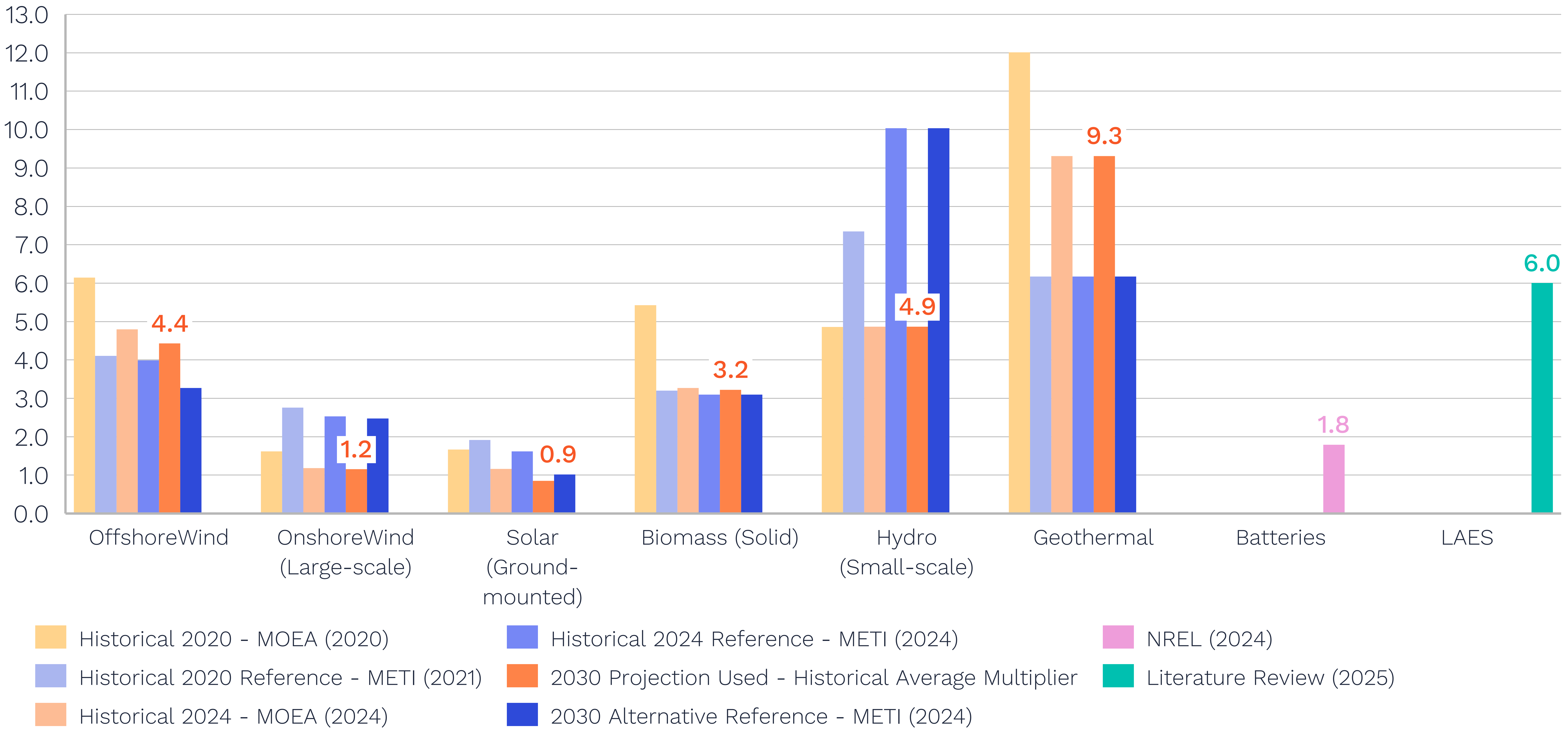
Notes

- We have identified five gas-fired power plant development projects from the MOEA 2023 Annual Business Plan that were commissioned within the last five years. Projects that commenced construction prior to this period were excluded, as their cost structures may not reflect the most up-to-date CAPEX profiles.
- These projects averaged US$1.5 million per MW in CAPEX. Although this figure is lower than comparable estimates in Japan, we consider it a reasonable proxy for the expected CAPEX of new gas-fired power plants in 2030 as it may reflect the country's recent wave of rapid capacity additions. This estimate assumes no significant future cost reductions from further improvements in technology readiness.
- We noticed the same CAPEX being used for building new gas and gas-hydrogen cofiring power plants in Japanese data for 2030. We have followed this approach in Taiwan as well.
- For CCS-equipped gas plants, we have utilised the observed 2030 CCS CAPEX markup projection used by the Japanese government on its conventional gas power plants. Being an emergent technology, we decided to use the same mark-up for gas CCS in Taiwan.

Renewable technology characteristics

We employ the Japanese government's most recent technology cost projections as proxy to Taiwanese cost estimates

Technology CAPEXes[1] (million US$/MW)



Notes

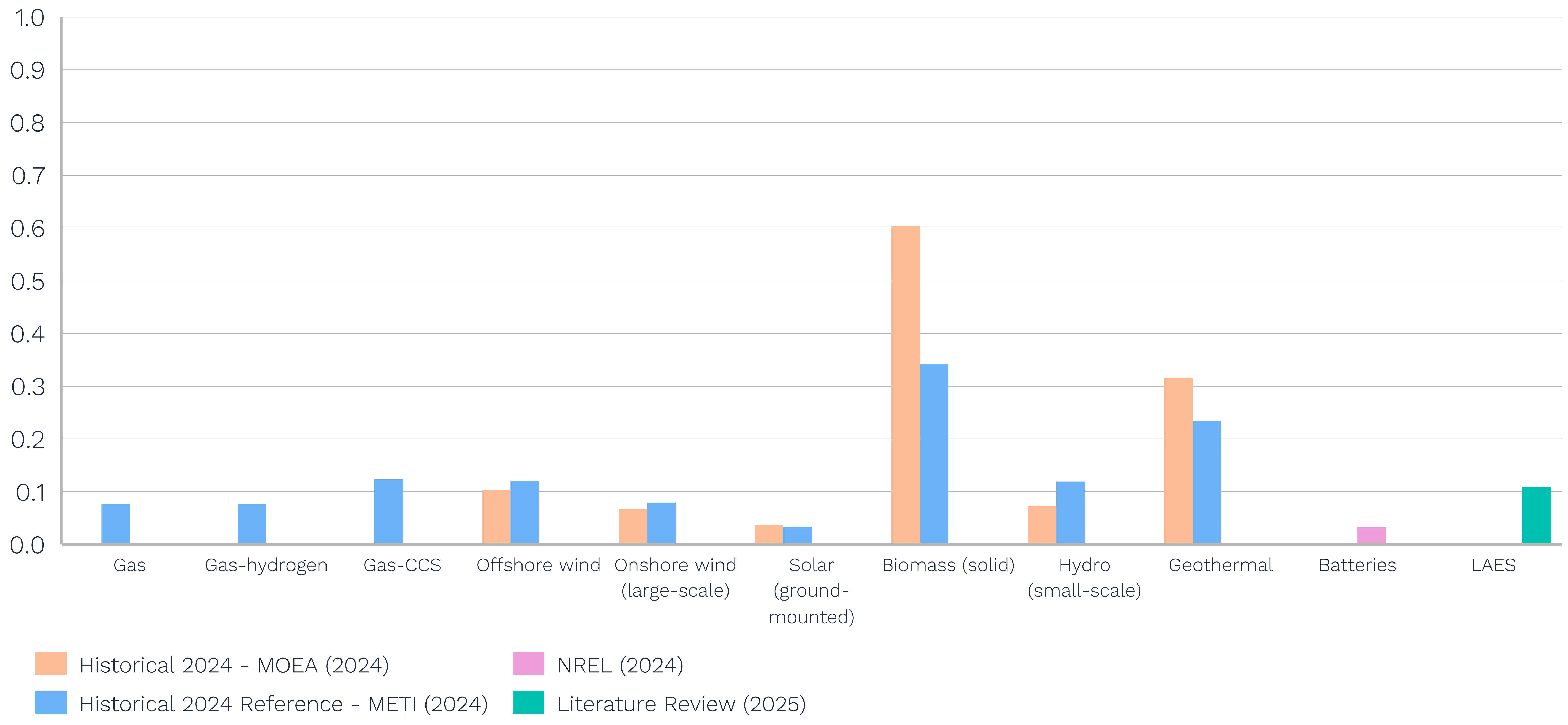
- Being unable to identify reliable 2030 CAPEX projections from authoritative sources in Taiwan, we relied on Japanese sources on CAPEX forecasts for our estimated model inputs.
- Historical Taiwanese CAPEX data were sourced from the annual Feed-in Tariff (FiT) committee meetings.
- We focus exclusively on the CAPEX of large-scale onshore wind and ground-mounted solar, acknowledging that Taiwan — with limited flat land — is likely to fully utilise its prime wind sites with large-scale development for economic attractiveness and that available rooftop space for small-scale solar is approaching saturation.
- We only consider the technology costs of biomass generation using solid-state fuels, reflecting the Taiwanese ambition of retrofitting retired coal power plant into biomass fired power plants, unlike biogas and waste which used primarily for cogeneration.
- We include the technology cost of small-scale hydropower to reflect Taiwan's constrained hydropower expansion potential due to limited suitable sites.
- For storage technologies, we followed NREL's cost projection for batteries and did our own literature review for LAES given its relatively low tech readiness and market maturity.
- All values were converted to USD using the average yearly exchange rate from the IMF.

[1] *CAPEXes shown are expressed in 2023 real money base*

Technology characteristics

We gathered the most up-to-date data from annual Feed-in Tarriff committee meeting records

Technology fixed operating costs[1] (million US$/MW)



Notes

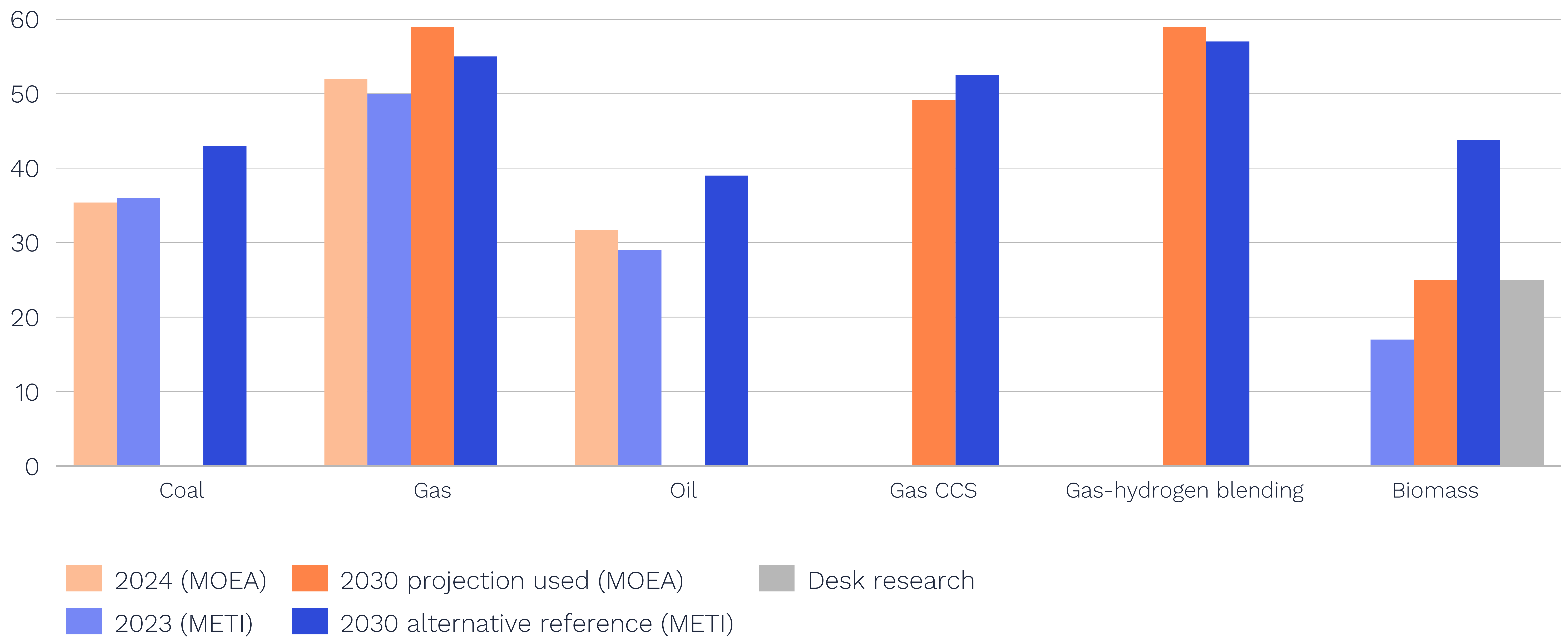
- Most recent annual fixed operating cost data for renewables are available from the annual Feed-in Tariff (FiT) committee meetings which we have utilised directly into our model final cost assumptions, assuming the cost needed to operate each technology stay the same up until 2030. We have observed the same assumptions being made by the Japanese government.
- For thermal technologies, we were not able to identify any authoritative fixed operating cost data, and therefore decided to rely on Japanese sources.
- To align with CAPEX cost assumptions, we focus exclusively on the fixed operating cost of large-scale onshore wind, ground-mounted solar and small-scale hydropower.
- All values were converted to USD using the average yearly exchange rate from the IMF.

[1] *Fixed operating costs shown are expressed in 2023 real money base*

Thermal technology characteristics

We calculated their efficiency based on asset-level lower heating value and auxiliary power consumption data reported by Taipower in its 2024 Annual Report

Efficiency by technology (%)



Notes

- For our model calibration of the year 2024 we derived average thermal efficiencies for the existing generation fleet from 2024 Taipower Annual Report.
- According to the 2023 National Power Resources Supply and Demand Report, no new coal or oil-fired power plants are planned for construction between now and 2030. Existing fleet after accounting for scheduled retirements is expected to maintain the same thermal efficiency as in previous years.
- We have assumed that gas-fired power plants built between now and 2030 will have the same efficiency as the most recent plants to come online which are Tungxiao #1 -#3, and Datan #8.
- We assume gas-hydrogen blending to operate at the same efficiency as normal gas plant.
- For gas CCS, we have accounted for the efficiency penalty with CCS installation by multiplying the efficiency of unabated gas plants by the multiplier between unabated and CCS-enabled CCGT plants from the DEA Tech Catalogue.
- We struggled to identify any reliable local data for biomass but have found several comparable data sources including Japanese METI. In the end we relied on desk research, as the METI projection seemed at odds with historically observed values (likely reflecting the efficiency of co-firing biomass with coal).

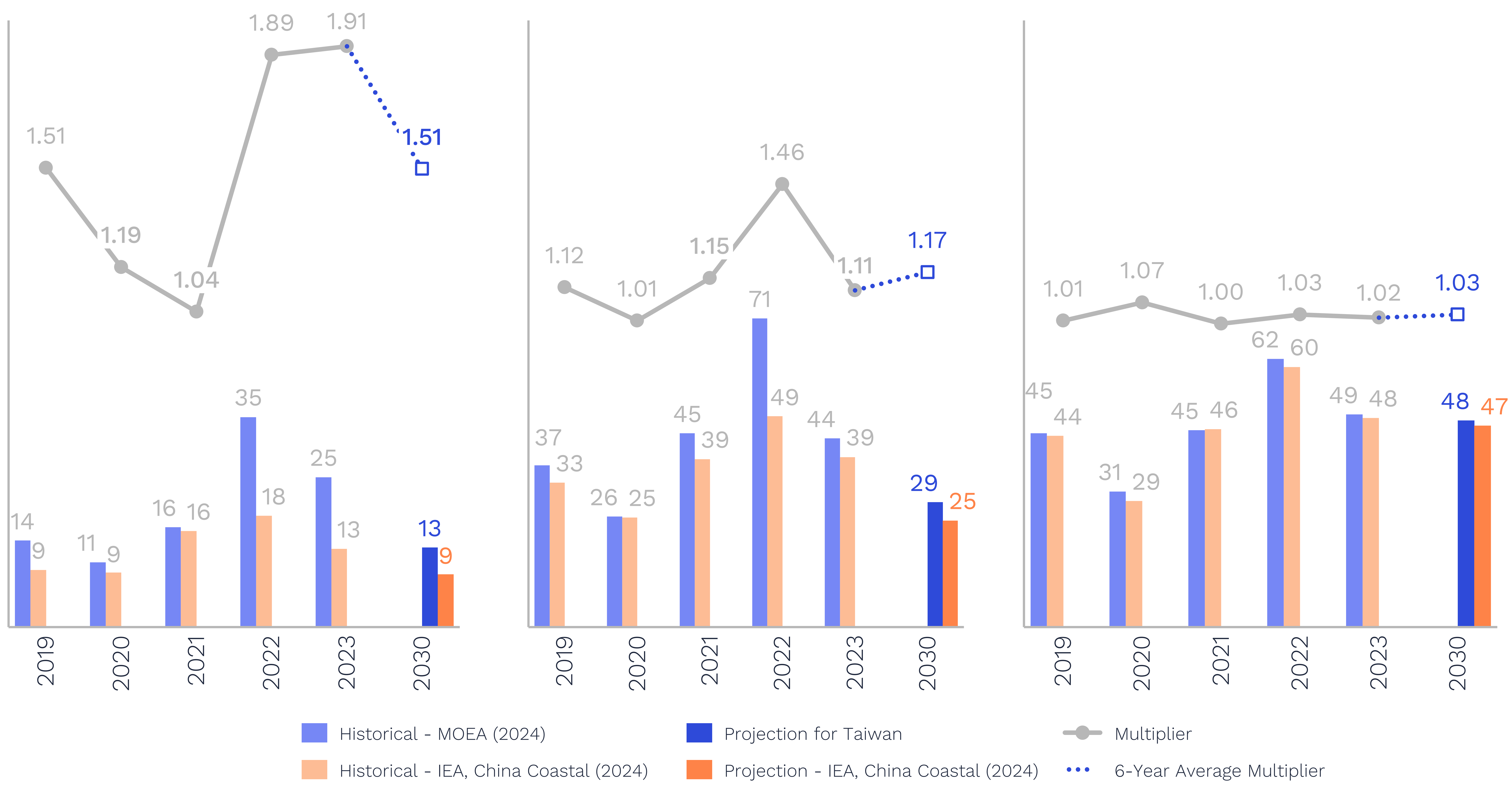
Fuel prices

How we derived our fossil fuel costs

Coal prices[1] by different sources and vintage year (USD/MWh)

Gas prices[1] by different sources and vintage year (USD/MWh)

Oil prices[1] by different sources and vintage year (USD/MWh)



Notes

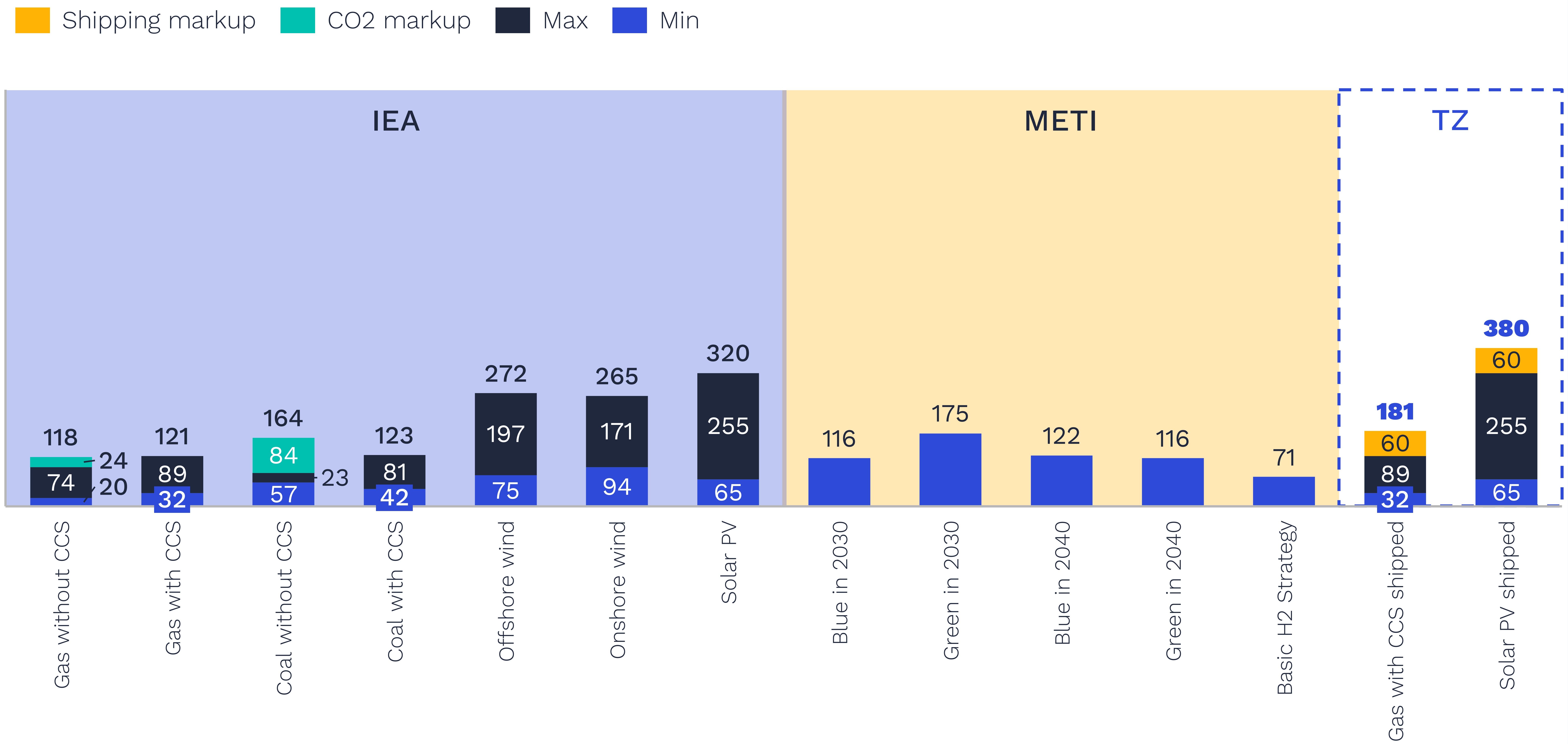
- We tracked data on commodity prices over the past six years from both the Taiwan MOEA and the IEA for Coastal China.
- We observed that Taiwan MOEA consistently reports a markup over IEA China Coastal values, with the highest disparity seen in coal and a comparatively minor difference in oil. We suspect the coal premium likely reflects environmental regulations imposed by the Taiwanese government, which requires higher-quality coal.
- We decided to leverage the observed relationship between MOEA and IEA China Coastal prices by applying a six-year average multiplier to the IEA China Coastal 2030 projections, to derive a reasonable estimate of Taiwan's commodity prices in 2030.

[1] *Fuel prices shown are expressed in 2023 real money base*

Fuel prices

We derived hydrogen price from production costs plus shipping

Hydrogen prices by different sources (USD/MWh)



Notes

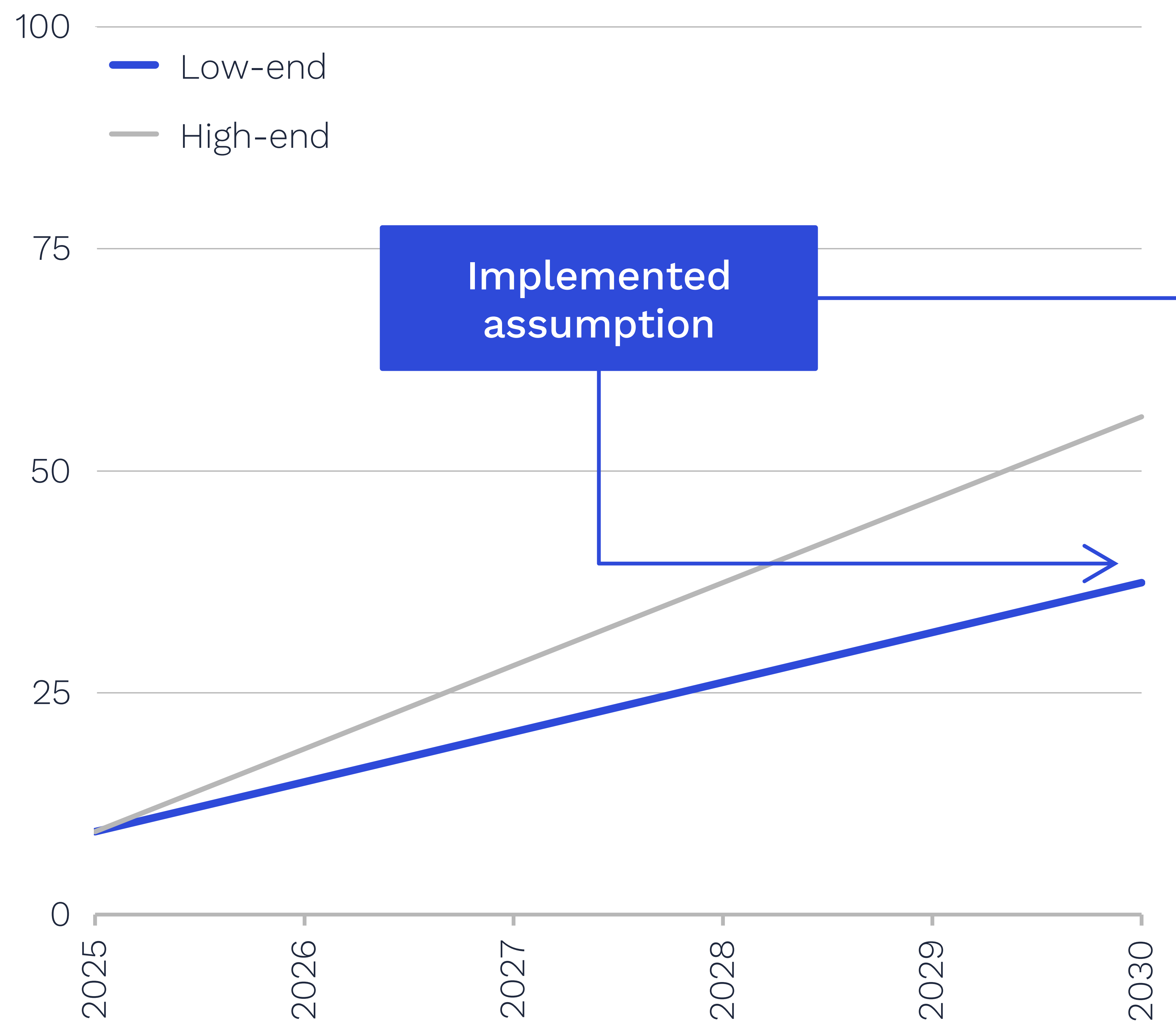
- To derive price projections for hydrogen we compared production costs estimated by the IEA in its 2024 Global Hydrogen Review with expected costs of delivery from several Japanese METI documents.[1]
- For blue hydrogen, considering that Taiwan is a price taker on gas, we decided to use the upper bound of the IEA's projection for production from gas with CCS and then apply shipping costs.[2]
- For green hydrogen, we used the IEA's maximum price for production from electrolysis powered by solar power, marked up by the same shipping costs.
- All fuel prices here refer to pure hydrogen, prior to blending with gas respectively.

[1] Projections for 2030 are from the 2021 report of the Generation Cost Verification Working Group. Projections for 2040 are from the 2024 vintage of the same report. Projections from the 2023 Basic Hydrogen Strategy are for 2030.
[2] For hydrogen we used the estimated cost of shipping liquid hydrogen from the IEA's 2024 Global Hydrogen Review assuming shipment from Darwin, Australia.

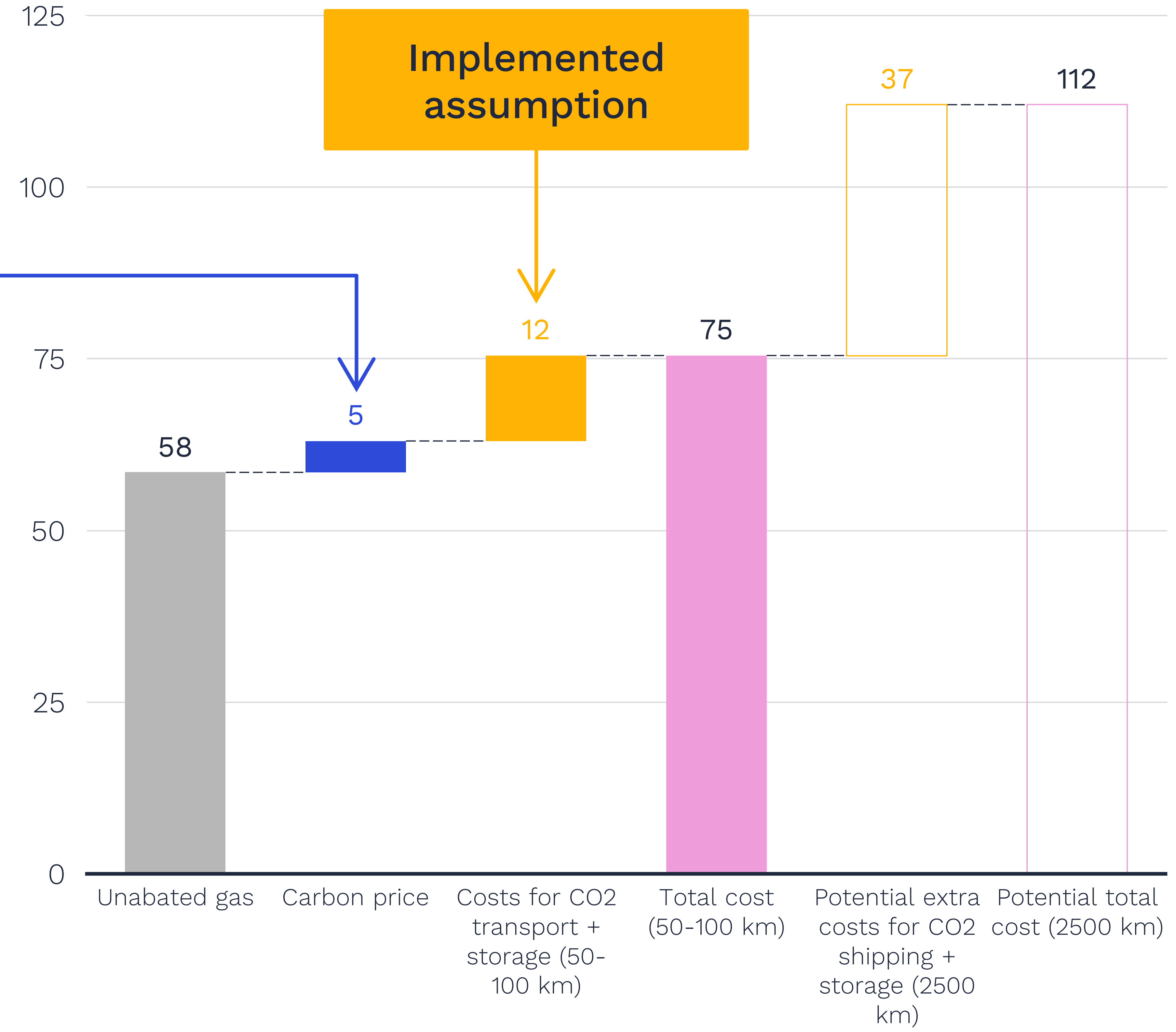
Carbon pricing and CCS

The shape of carbon pricing policy and arrangements around CCS burden sharing have material impacts on the performance of innovative thermal plants

Carbon price (USD/tCO_2e)



Generation cost components for gas with CCS[2] (USD/MWh)



Source: MOENV, METI, IEEJ.

Notes

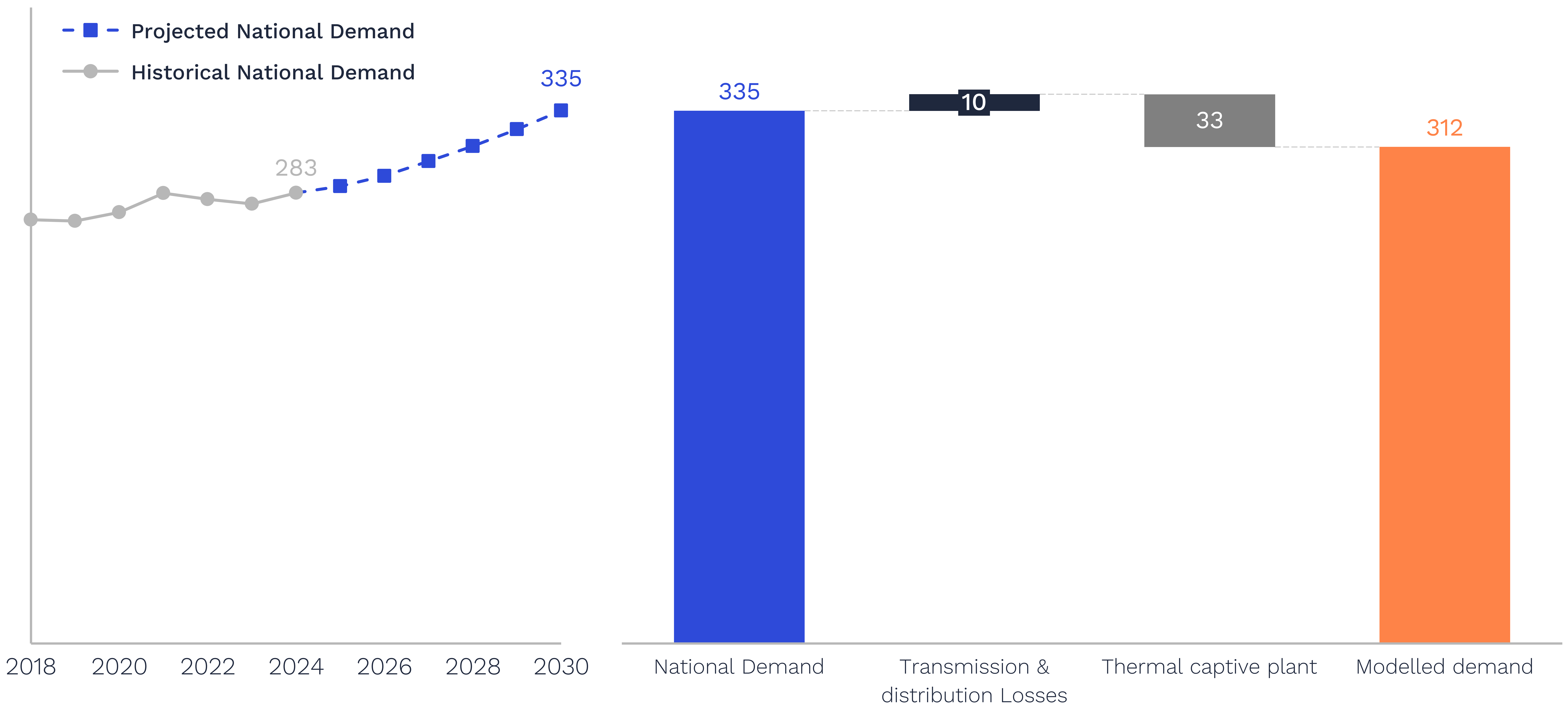
- Taiwan's carbon policy is in its early stages, with carbon pricing for major emitters starting in 2025, for large power generators and manufacturing companies emitting over 25,000 tCO_2e annually.
- We model Taiwan's future carbon prices as a carbon fee set as the upper limit envisioned by the government. This reflects our conservative assumption that verified emission reductions will be insufficient to trigger preferential, lower rates. The initial standard rate is NT$300 (USD9) /tCO2e and is projected to rise gradually to NT$1,200-1,800 (USD37-56) by 2030. We have taken the lower edge of the range as our final model input.
- The implications for existing fossil generators on the brownfield is that the merit order of gas and coal-fired plants changes, whereas on the greenfield in TP3, innovative thermal become less competitive against renewables.
- Further costs affecting CCS arise from the need to transport CO_2 by pipelines and store it in sequestration sites. We used cost estimations from the Japanese government for storing CO_2 that has been delivered through 200km of pipelines.
- The only current CCS testing site is located at Taichung which is along the central coast. Its coastal location makes it accessible by pipeline, and importantly, all future potential convertible gas-fired power plants are also situated along the coast, around 100-200 km away from all potential CCS plant sites. supporting the feasibility of a connected CCS pipeline infrastructure.
- Using Japanese government sources, we have also included an estimate of the costs in a scenario where storage in Taiwan is not feasible and CO_2 captured would need to be shipped to and stored in Malaysia.[1]

.[1] The distance to the depleted Petronas M3 field near the Bintulu LNG terminal in Malaysia is roughly 2500 km, assuming departure around central Taiwan.
.[2] The costs shown are weighted by the capture rate of 70%. And leakage rate of 30%.

Demand

We follow governmental demand projections for 2030

2030 National Demand Projection (TWh)



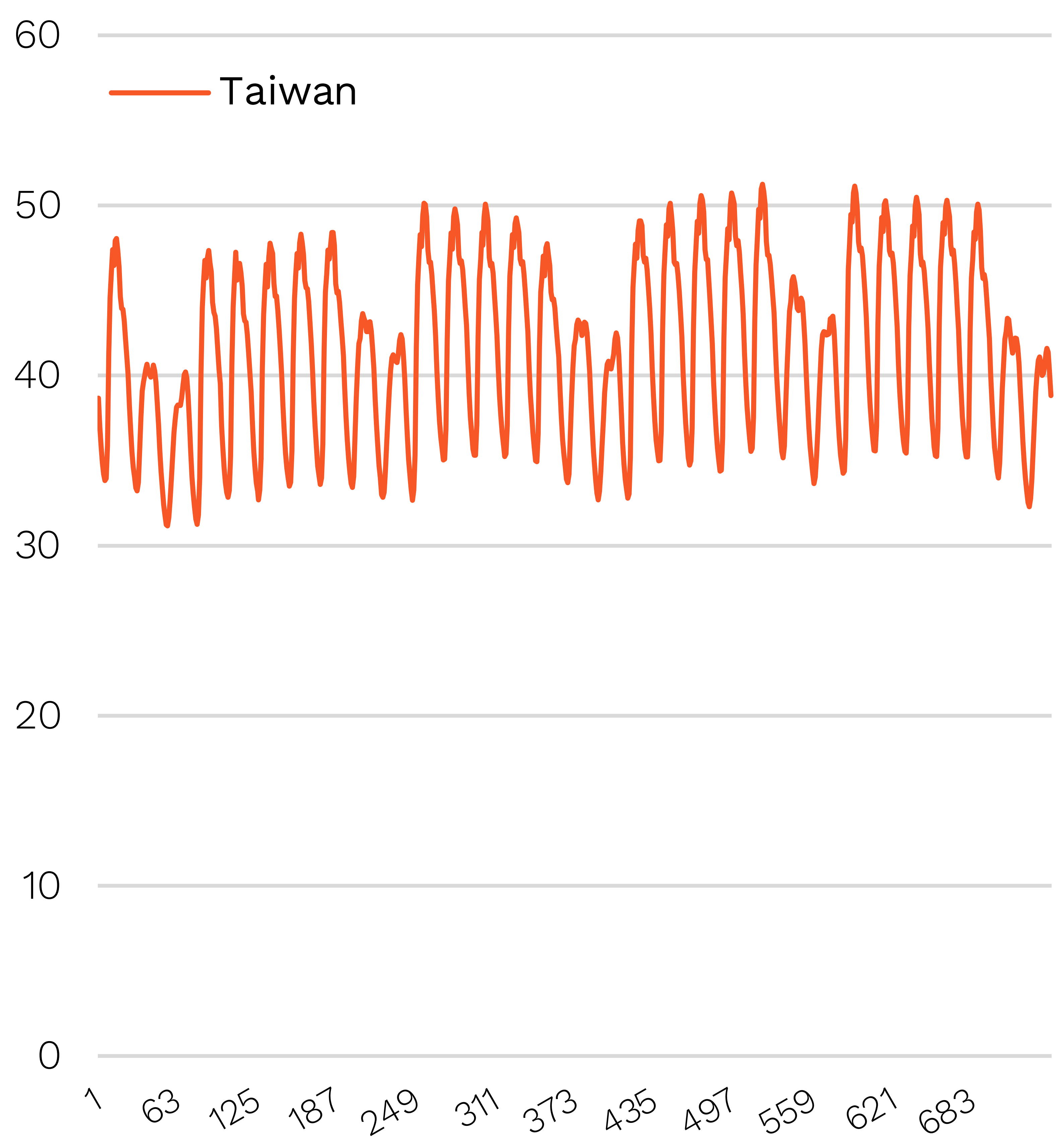
Notes

- Our demand projection for 2030 is in line with the projection presented on 2023 Electricity Demand and Supply Report.
- We derived Taiwan's modelled electricity demand by adding transmission and distribution (T&D) losses to national demand and subtracting demand met by thermal captive plants, focusing only on the portion managed by the grid operator.
- T&D losses are calculated as a percentage of national demand, using the historical average to project losses in 2030. For thermal captive plants, we apply the historical average of absolute demand and assume it remains constant over time.
- We understand that rooftop solar PV is included in the government's projected national electricity demand for 2030. Accordingly, we have reflected this in our model by accounting for the projected growth of behind-the-meter rooftop solar on the supply side.

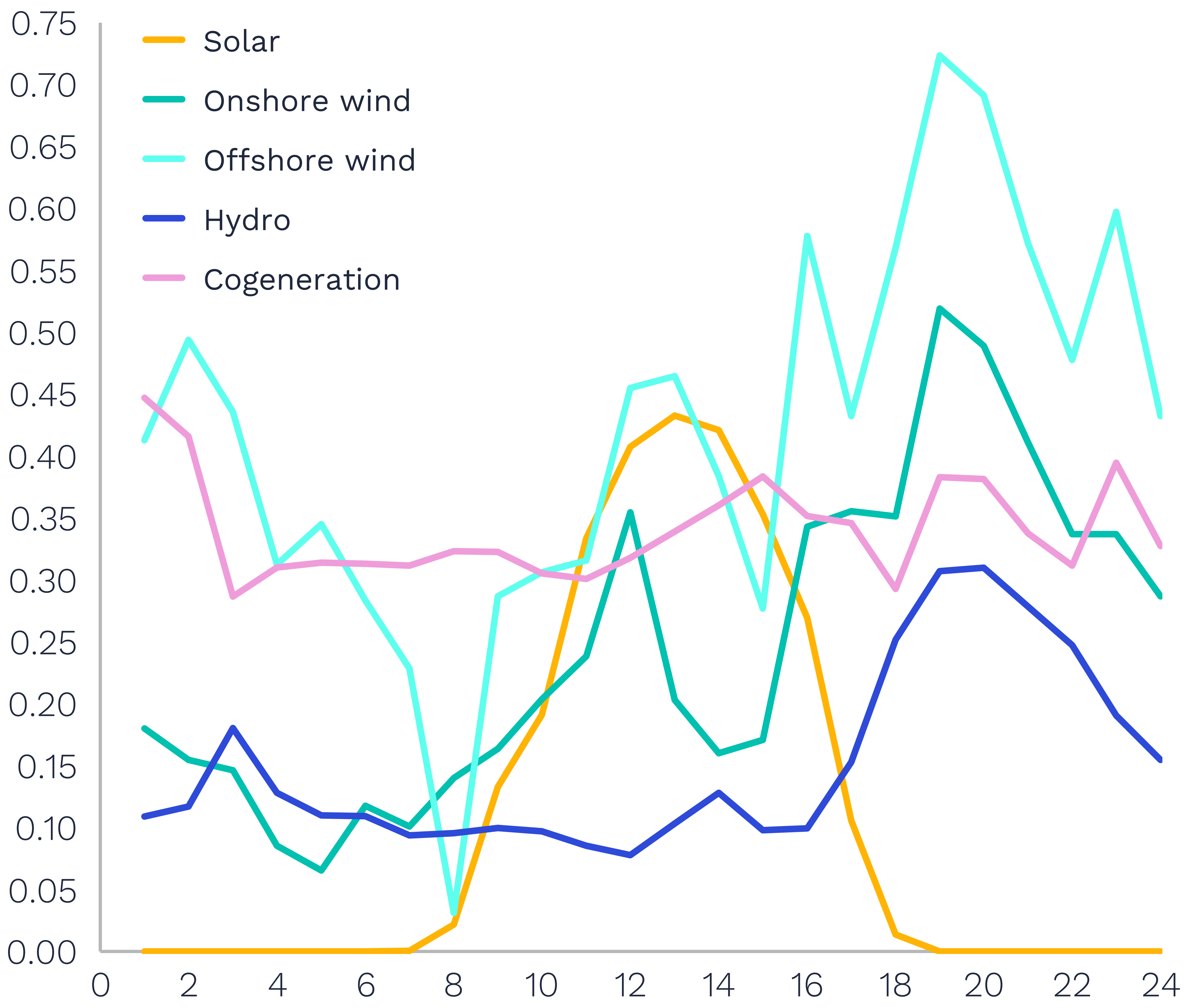
Demand

We construct historical hourly data for demand and renewable generation

2030 hourly demand profile of the representative July month for Taiwan (GWh)



2030 Hourly generation profile across different renewables of a representative day for Taiwan (%)



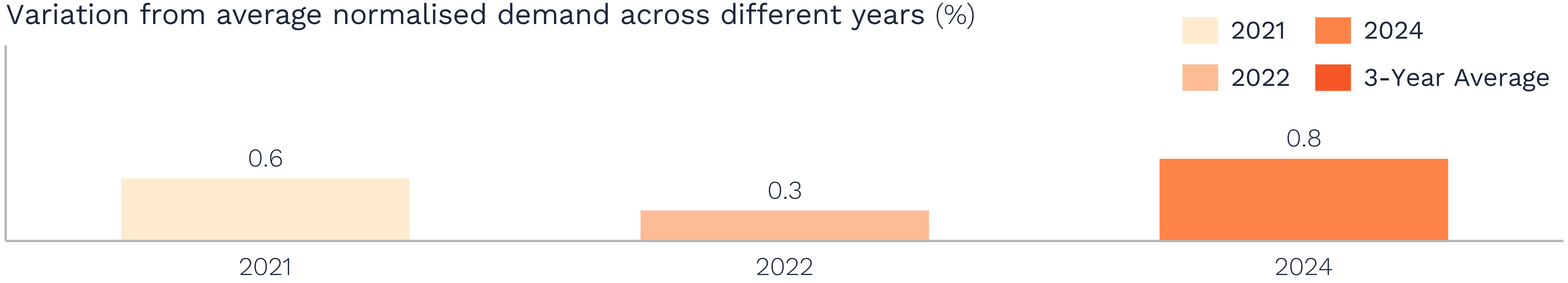
Notes

- On the brownfield bus we implement a historically observed 8,760-hour demand profile sourced indirectly from Taipower through third-party vendor of ElectricityMaps, as well as a renewable generation profile.
- As the contribution of cogeneration to the grid is highly unreliable and uncertain, we decided to treat it like other intermittent renewables whereby we constructed a unique hourly generation profile throughout the year.

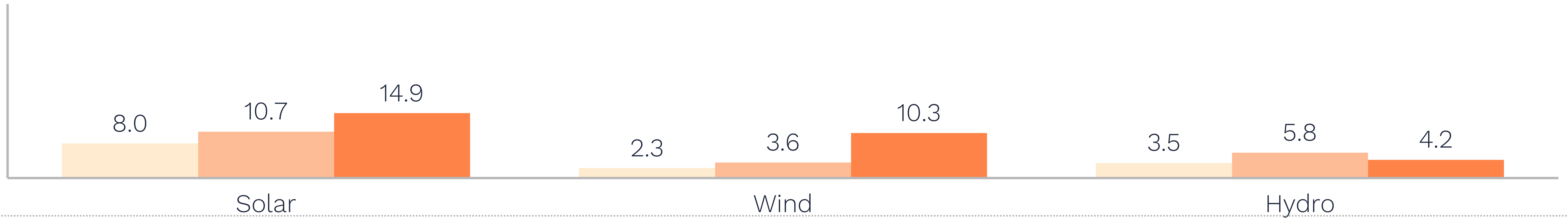
Demand

We selected 2022 as our weather year based on variance analysis on both demand and supply

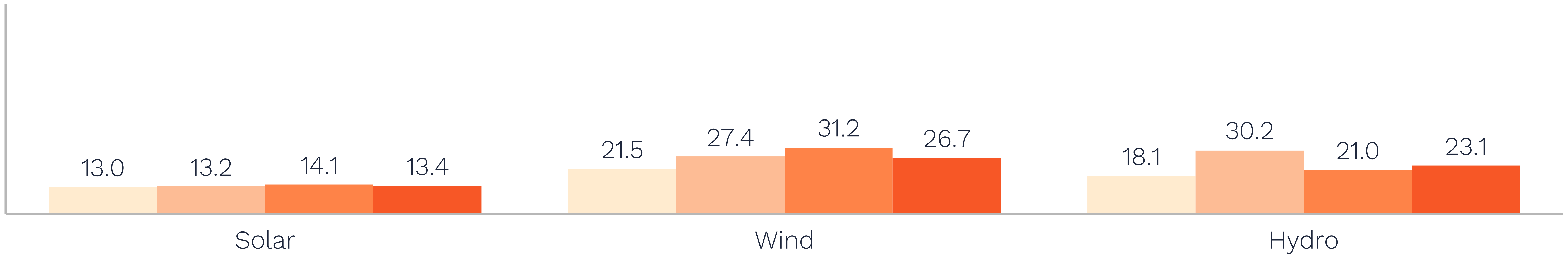
Variation from average normalised demand across different years (%)



Power generation across intermittent renewables across different years (TWh)



Yearly capacity factor across different years and intermittent renewables (%)



Notes

- Based on our variance analysis, we selected 2022 as the representative weather year for the model's 8,760-hourly seasonal variation accounted demand profile, as it showed the lowest deviation, 0.3%, from the 3-year average normalized demand.
- On the intermittent supply side, both solar and wind also exhibited minimal variation from the average in 2022.
- We further differentiated onshore and offshore wind with separate and distinct 8,760-hour generation profiles.
- Although hydro showed a larger deviation, its overall contribution to total supply is minimal.
- We acknowledge that using a different weather year could have produced noticeably different modelling outcomes. The optimal approach would involve testing multiple weather years, but this lies beyond the scope of our current study and is an area we hope to explore in the future.

Attribution

To cite this document and the larger body of CFE work from TransitionZero, use the following:

> *Luta, A., Mohamed, I., Puspitarini, H. D., Suarez, I., Shivakumar, A., Yap, J., & Welsby, D. (July 2025). System-level impacts of 24/7 Carbon-Free Electricity (CFE) in India, Japan, Malaysia, Singapore, and Taiwan. TransitionZero.*

The modelling in this report is based on TransitionZero's country-level 24/7 CFE framework, built using the PyPSA (Python for Power System Analysis) platform. The model and methodology will be released under the AGPL-3.0 open-source license in September 2025. This license requires that any public use or adaptation of the model be shared under the same terms. Documentation and data files can be downloaded at: transitionzero.org/cfe.

TransitionZero

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