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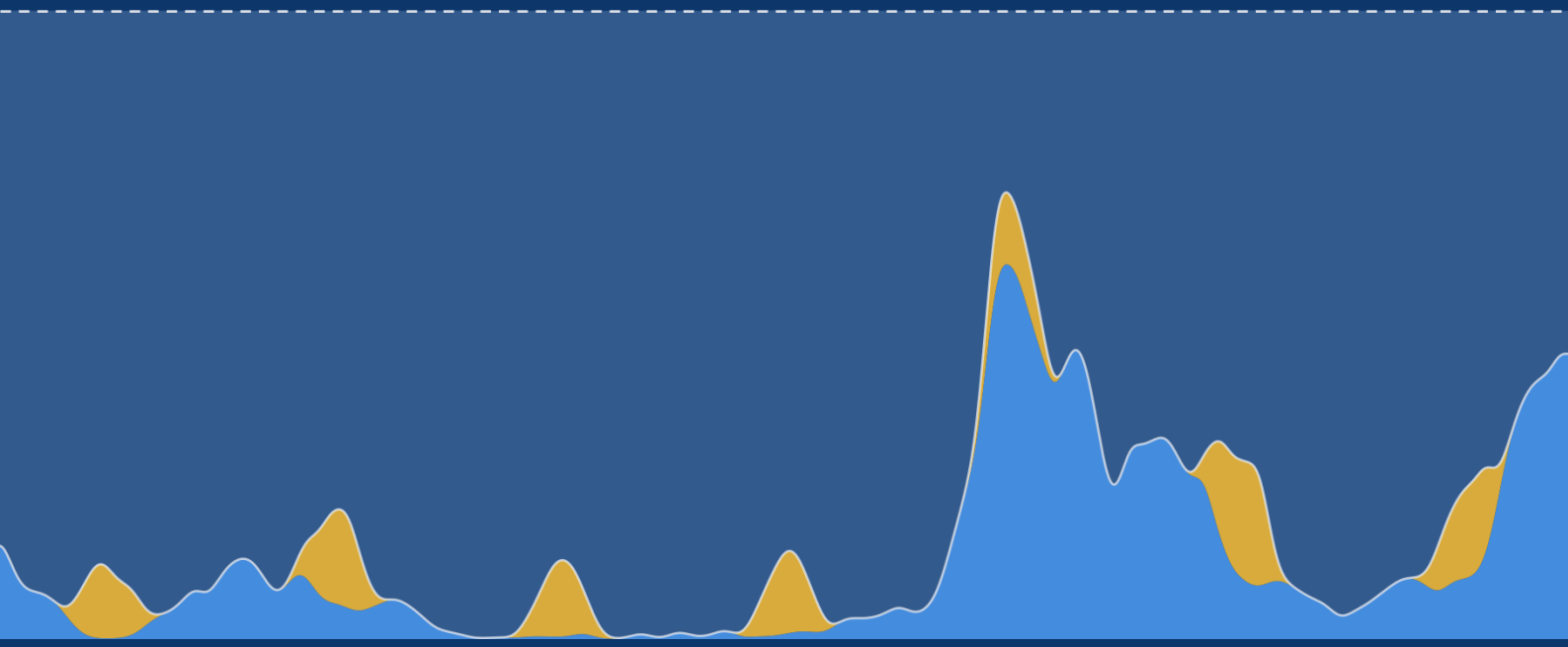
Firming wind and solar: fuel cells or gas turbines?

What round-the-clock power costs from optimised wind, solar and gas back-up in western Denmark, northern Germany and Spain, and how the answer changes from 10 MW to 2 GW

Prepared by **Stephen B. Harrison**, Managing Director of sbh4 consulting, Germany

November 2026 · 1 GW flat load, off-grid, with a scale analysis from 10 MW to 2 GW · hourly weather, gas and CO2 prices Oct 2023 – Sep 2026 · 10% WACC · real 2025 €

NORTHERN GERMANY, 4–10 NOVEMBER 2024: WIND (BLUE), SOLAR (GOLD) AND GAS (SLATE) MEETING A FLAT 1 GW LOAD



€102–128
per MWh for 1 GW of firm power from wind, solar and OCGT back-up

€167–174
per MWh from the same gas turbines running alone

+€13–16
per MWh for a reformer + fuel-cell back-up at 1 GW scale

30–37 MW
firm load below which a modular fuel cell beats the OCGT

Techno-economic analysis based on public weather, cost and market data. Not investment advice; see the disclaimer in Annex C.

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CONTENTS

Contents

1	Executive summary	3
2	Why firm power, and the question this paper answers	4
3	Data you can bank on	6
4	Sites and optimised system design	7
5	The winter test	9
6	What firm power costs	10
7	Fuel cell or gas turbine?	12
8	Scale: where the fuel cell wins	14
9	Emissions	18
10	Economics at a fixed sale price	19
11	Sensitivities	20
12	Limitations	22
Annex A	Methodology	23
Annex B	Assumptions register	24
Annex C	References and disclaimer	25
About the author and contact		27

Basis of the numbers. Levelised cost of electricity (LCOE) in € per MWh delivered to a flat 1 GW load in every hour of the year (8.77 TWh/yr), from a dedicated off-grid plant with no grid connection and no storage. Costs are in real 2025 € with a 10% weighted average cost of capital (WACC). Wind and solar output are modelled hour by hour from October 2023 to September 2026; gas and EU ETS carbon prices are the monthly averages of the same 36 months. For each site the wind and solar capacities are optimised for the lowest total cost; the gas back-up is always sized for the full 1 GW. Section 8 repeats the fuel cell and OCGT comparison for firm loads from 10 MW to 2 GW.

The three back-up options. A natural-gas steam reformer feeding a fuel cell (65% × 76% = 49.4% LHV, €2,000/kW installed), an open-cycle gas turbine (OCGT, 40% LHV, €850/kW) as the benchmark and a combined-cycle gas turbine (CCGT, 58% LHV, €1,500/kW). Sources and ranges are in Annex B.

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SECTION 1

Executive summary

€102–128
per MWh: firm 1 GW from optimised wind + solar with open-cycle gas turbine (OCGT) back-up

+€13–16
per MWh premium for reformer + fuel-cell back-up at €2,000/kW over the OCGT, at 1 GW scale

30–37 MW
break-even firm load: below it, a modular fuel cell is cheaper than an OCGT

61%–73%
of the year's demand met directly by wind and solar in the optimised designs

Key findings

- **Wind and solar make firm power cheaper, not dearer.** An optimised hybrid with OCGT back-up delivers 1 GW in every hour for €102/MWh in western Denmark, €109/MWh in Spain and €128/MWh in northern Germany. The same turbines running alone on gas would cost €167–174/MWh, so the hybrid is 27%–41% cheaper.
- **The site matters more than the back-up.** Strong wind (3,500 full-load hours in west Jutland) or strong sun (1,877 kWh/kWp on trackers in Aragón) keeps costs down. Northern Germany is dearest, with 2,774 full-load hours and higher capex. With OCGT back-up the spread between sites is €26/MWh, larger than the gap between back-up technologies at any one site.
- **The back-up runs part-time, so capex decides.** The gas plant must be sized for the full 1 GW but delivers only 2,324–3,432 full-load hours a year (27%–39% load factor). At that duty and at 1 GW scale, the OCGT at €850/kW beats a reformer + fuel cell at €2,000/kW by €13–16/MWh at every site, despite the fuel cell's higher efficiency (49.4% against 40% LHV).
- **The fuel cell needs lower capex, not higher efficiency.** It would match the OCGT hybrid at about €1,128–1,288/kW and the CCGT hybrid at about €753–876/kW. As a stand-alone plant it overtakes the OCGT only above about 7,300 full-load hours a year. No single input tested in Section 11 closes the gap.
- **Small projects favour the fuel cell.** Gas turbines have strong economies of scale (cost scaling index about 0.62) and lose efficiency below about 34 MW; fuel cells are modular. Below about 30–37 MW of firm load the fuel cell is the cheaper back-up, by €23–29/MWh at 10 MW. From about 50 MW the OCGT wins, by €3–6/MWh at 50 MW and €13–16/MWh at 1 GW. If a spare gas turbine is required (N+1), the crossover rises to about 100 MW.
- **A CCGT would be cheapest at 1 GW, if it could cycle daily.** With 58% efficiency it overtakes the OCGT above about 1,680 full-load hours, giving €97–118/MWh. However, conventional combined cycles start in hours rather than minutes, so the CCGT is an option only for large projects with a fast-start design. The OCGT remains the practical benchmark.
- **Calm, dark weeks set the design.** In the week from 4 November 2024 (fuel-cell designs), gas met 85% of demand in western Denmark, 85% in northern Germany and 62% in Spain. The optimum is about 3.0–3.2 GW of wind and solar per GW of firm load, curtailing 11%–17% of their output.
- **Gas is the largest risk; capital the largest lever.** At September 2026 gas and carbon prices, costs rise by €20–34/MWh. Financing at 6% instead of 10% lowers them by €14–20/MWh.
- **Emissions fall by around two-thirds.** The hybrids emit 101–177 g CO2/kWh against 348–505 g/kWh for the same back-up plant running on gas alone, a reduction of 61%–73%.

> **Implication for developers, offtakers and investors.** Renewable-led, round-the-clock power costs around €102–128/MWh at the three sites studied, using proven gas turbines for firming. Site resource and the cost of capital move the price more than the choice of back-up. At 1 GW scale a reformer + fuel cell becomes competitive as firming plant only if its installed cost falls from €2,000/kW to about €1,128–1,288/kW. For projects below about 30–37 MW, its modularity makes it the cheaper back-up at the assumed cost.

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SECTION 2

Why firm power, and the question this paper answers

Wind and solar are now the lowest-cost sources of new electricity in Germany [7] and in much of Europe. However, many customers need power in every hour of the year, not only when the wind blows or the sun shines.

Data centres, continuous industrial processes, green iron and steel from the combined direct reduced iron (DRI) and electric arc furnace (EAF) route, steel recycling with EAFs, electrolysers designed for steady operation and island or weak-grid sites all value firmness. Round-the-clock supply contracts and 24/7 clean-energy targets are the commercial expression of that need. The engineering question is how to turn variable output into a firm supply at the lowest cost: batteries cover hours, gas-fired plant covers any duration and hydrogen-based routes are often proposed as the low-carbon long-term option.

This paper isolates the cost of firmness. A dedicated, off-grid plant must deliver exactly 1 GW in every hour from October 2023 to September 2026. Wind and solar are sized hour by hour for the lowest cost; gas-fired back-up covers every shortfall; surplus output is curtailed. Three back-up options are compared, each as a hybrid with renewables and on its own:

- **Reformer + fuel cell:** natural gas is reformed to hydrogen (76% LHV [17]) and converted in a high-efficiency fuel cell (65% LHV), giving 49.4% overall.
- **Open-cycle gas turbine (OCGT):** the fast-starting peaking benchmark, 40% LHV.
- **Combined-cycle gas turbine (CCGT):** the efficient mid-merit option, 58% LHV.

Section 8 then asks how the answer changes with project size. For firm loads from 10 MW to 2 GW it compares the OCGT, whose cost per kW falls steeply with size, with a modular fuel cell.

Table 1. The study at a glance

Load	1 GW flat, every hour: 8,768 h/yr and 8.77 TWh/yr (average of Oct 2023 – Sep 2026)
Sites	West Jutland, Denmark (56.0°N, 8.5°E); Schleswig-Holstein, Germany (54.25°N, 9.25°E); Aragón near Zaragoza, Spain (41.5°N, 1.0°W)
Weather	Hourly ERA5 reanalysis, Oct 2023 – Sep 2026 (26,304 hours), calibrated to long-term wind and solar yields [1–6]
Renewables	Onshore wind and single-axis tracking or fixed solar; capacities optimised on a 0.01 GW grid
Back-up	1 GW of reformer + fuel cell, OCGT or CCGT; gas and EU ETS carbon at monthly prices [13–16]
Scale	Firm loads of 10, 50, 100, 200, 500, 1,000 and 2,000 MW: back-up capex and OCGT efficiency vary with size (Section 8)
Finance	10% real WACC; wind 25 years, solar 30, OCGT and CCGT 25, fuel cell 20
Not included	Grid connection, storage, sales of surplus power, ancillary-service revenue, tax and subsidies

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Green steel: how much power, and how firm? An EAF melts scrap or DRI with an electric arc. Furnace electricity use ranges from below 300 kWh per tonne of liquid steel in the most efficient designs to around 450–500 kWh/t in older, smaller plants [32–34]. A scrap-based mill making 1 to 2 million tonnes a year therefore needs roughly 45 to 90 MW on average for its furnaces alone, but draws it in short, heavy blocks: a single 170 t furnace is rated at 160 MVA [28]. The hydrogen route needs about ten times as much, at about 3.5 MWh of electricity per tonne of liquid steel, mostly for electrolysis [29]. On that basis a 2.5 Mt/yr plant would use about 8.7 TWh a year, close to the 8.77 TWh/yr modelled here. For scale, the first stage of Stegra's plant at Boden in Sweden targets 2.5 Mt/yr with about 700 MW of electrolysers [30, 31].

Firmness matters at two time scales. Within a heat the furnace needs full power: an interruption leaves a part-melted charge and lost output. The arc also draws large, rapid swings of reactive power. At one 170 t furnace on a 400 kV grid, swings of up to 249 Mvar pushed flicker to twice the permitted level until a 225 Mvar static VAR compensator was fitted [28]. Off-grid, the back-up plant, inverters and compensation must supply this without a large grid behind them. On the other hand, the melt shop can be scheduled: with stocks of DRI and scrap it need not run continuously, while hydrogen storage can keep the DRI shaft furnace supplied as the electrolysers follow wind and solar [29]. Scrap-based mills of 45 to 90 MW sit between the fuel cell and OCGT crossover without and with a spare gas turbine (Section 8); hydrogen-based plants are at the scale where the OCGT wins. The hourly model in this paper does not capture sub-hourly dynamics.

Why off-grid? A grid-connected plant could sell surplus and buy shortfalls, so its cost would depend on market prices and network tariffs. Removing the grid shows the physical cost of firmness at each site, before any benefit from trading or cost of network charges, and gives a fair basis for comparing back-up technologies.

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SECTION 3

Data you can bank on

Every input comes from a public, citable source of the kind used in project finance, regulatory filings and energy-system planning. Table 2 lists them; numbers in brackets refer to the references in Annex C.

Table 2. Data sources

Input	Source	How it is used
Hourly weather	Copernicus ERA5 reanalysis (ECMWF), via Open-Meteo [1]	Wind speed, irradiance and temperature for every hour, Oct 2023 – Sep 2026
Solar yield	EU Joint Research Centre PVGIS 5.3, SARAH3 [2]	Calibrates modelled solar output to the long-term yield at each site
Wind yield	Danish Energy Agency [3]; EEG reference yield and FA Wind und Solar quality factors [5, 6]; Spanish wind data [10, 11]	Calibrates net full-load hours of new turbines
Wind and solar costs	Danish Energy Agency [3]; Deutsche WindGuard [4]; Fraunhofer ISE [7]; Solar Data Atlas [8]; German PV auctions [9]	Capex and O&M by country
Gas prices	Energinet Energi Data Service (Danish and German hubs) [14]; MIBGAS (Spain) [13]; Trading Hub Europe storage levy [15]	Monthly delivered gas price for each site
Carbon	EEX EU ETS primary auctions [16]	Monthly allowance price
Gas plant	Danish Energy Agency [3]; Lazard LCOE+ [18]; Fraunhofer ISE [7]; GridLab [19]; OEM data [20, 21]	OCGT and CCGT capex, efficiency, O&M and flexibility
Reformer	IEA Global Hydrogen Review 2025, assumptions annex [17]	76% LHV efficiency and O&M

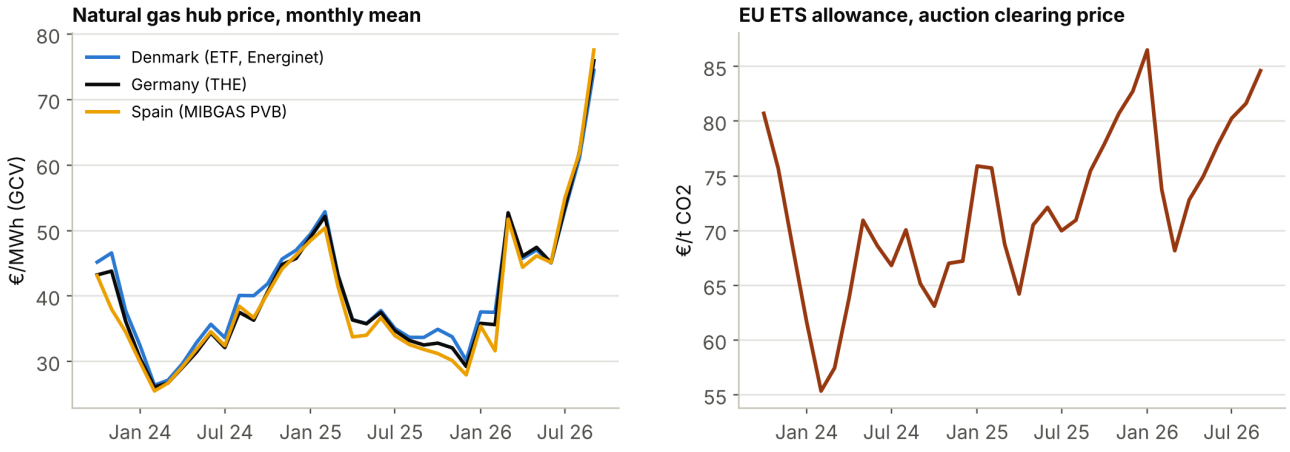


Figure 1. Market inputs, monthly means, October 2023 to September 2026. Gas averaged €41–43/MWh delivered across the three sites, rising to €76–79/MWh in September 2026; EU allowances averaged €72/t. Sources: Energinet [14], MIBGAS [13], EEX [16].

Two choices make the results robust. First, wind, solar and gas prices come from the same 36 months, so the cost of a cold, still winter week is captured together with the gas price paid in that week. Second, the hourly model was checked against an independent implementation (pvlib) on sample hours, agreeing to within about 0.002 kW per kW of capacity.

SECTION 4

Sites and optimised system design

The three sites represent three resource profiles: a strong wind site, a northern German wind site with average yields and a solar-rich Spanish site with moderate wind.

Table 3. Resource and renewable costs by site

Site	Wind full-load hours/yr	Solar yield, tracker kWh/kWp/yr	Wind capex €/kW	Solar capex, tracker €/kWp	Delivered gas €/MWh, mean
Western Denmark	3,500	1,168	1,420	500	42.4
Northern Germany	2,774	1,201	1,650	640	43.4
Spain (Aragón)	2,900	1,877	1,350	540	40.8

Lifetime-average yields after calibration (Annex A). Capex fully installed, real 2025 € (Annex B).

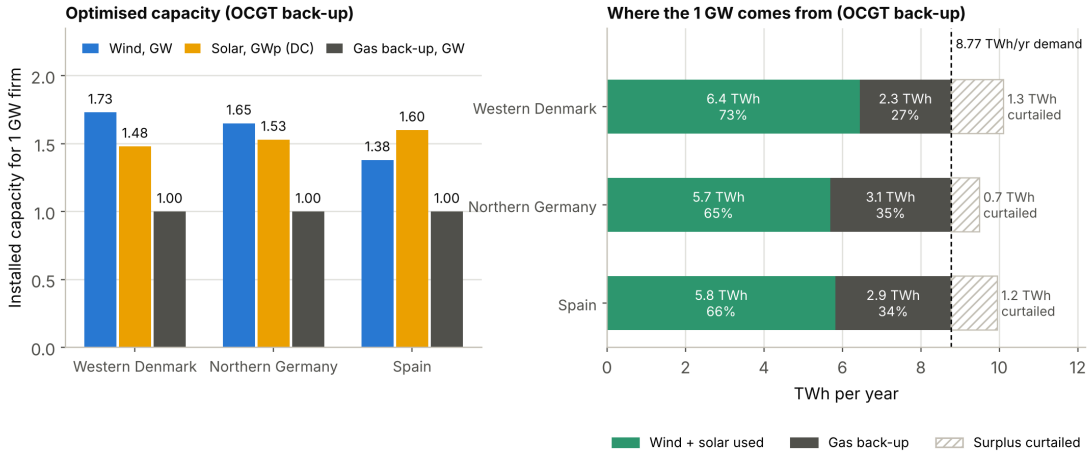


Figure 2. Optimised capacities and annual energy balance for the OCGT designs. Wind and solar deliver 65%–73% of demand; the rest comes from gas. Hatched: surplus output curtailed because there is no storage or grid export. Source: sbh4 hourly model with ERA5 [1] and PVGIS [2] calibration.

Table 4. Optimised designs for 1 GW of firm power

Site	Back-up	Wind GW	Solar GWp	Total capex €bn	Wind + solar share	Curtailed	Gas back-up GWh/yr
Western Denmark	Reformer + fuel cell	1.60	1.36	4.95	71%	13%	2,544
	OCGT	**1.73**	**1.48**	**4.05**	**73%**	**17%**	**2,324**
	CCGT	1.60	1.36	4.45	71%	13%	2,544
Northern Germany	Reformer + fuel cell	1.46	1.44	5.33	61%	8%	3,432
	OCGT	**1.65**	**1.53**	**4.55**	**65%**	**11%**	**3,078**
	CCGT	1.46	1.44	4.83	61%	8%	3,432
Spain (Aragón)	Reformer + fuel cell	1.28	1.53	4.55	64%	14%	3,124
	OCGT	**1.38**	**1.60**	**3.58**	**66%**	**17%**	**2,945**
	CCGT	1.28	1.53	4.05	64%	14%	3,124

Solar is single-axis tracking in every optimum. CCGT shown at the capacities optimised for the fuel cell; a full re-optimisation could only lower its cost.

What the optimiser chooses

About 3.0–3.2 GW of wind and solar are built per GW of firm load in the OCGT designs, with wind the larger part in Denmark and Germany and solar in Spain. The mix balances two effects: more capacity cuts gas use, but each extra

MW is curtailed more often. The optimum curtails 8%–17% of wind and solar output.

The cheaper each MWh of back-up energy, the less renewable capacity is worth building. The fuel cell burns less gas per MWh than the OCGT, so each MWh that wind and solar displace saves less, and the optimiser builds slightly less wind and solar around it. The size of the back-up does not affect the mix, because it is always 1 GW. A hybrid also beats either resource alone: with OCGT back-up, wind-only designs cost €109–137/MWh and solar-only designs €126–151/MWh, against €102–128/MWh for the optimised mix.

Table 5. A wind and solar mix beats either resource alone (€/MWh of firm power)

Site	Back-up	Wind only GW	Wind only €/MWh	Solar only GWp	Solar only €/MWh	Optimised mix €/MWh
Western Denmark	Reformer + fuel cell	1.84	122.3	2.36	147.9	117.6
	OCGT	**2.02**	**108.7**	**2.66**	**144.8**	**101.9**
Northern Germany	Reformer + fuel cell	1.72	147.1	2.06	153.7	140.5
	OCGT	**1.94**	**137.2**	**2.30**	**151.3**	**127.7**
Spain (Aragón)	Reformer + fuel cell	1.50	138.8	2.10	132.4	122.7
	OCGT	**1.66**	**129.7**	**2.30**	**126.0**	**108.7**

Each design re-optimised hour by hour with the other resource set to zero; back-up always 1 GW. Source: sbh4 hourly model.

> **Rule of thumb.** To deliver 1 GW firm at these sites, build around 1.4–1.7 GW of wind and 1.5–1.6 GWp of solar alongside 1 GW of gas back-up, and expect gas to supply 27%–35% of the energy.

SECTION 5

The winter test

Firm power is designed for the worst week, not the average one. In early November 2024 a prolonged spell of still, overcast weather settled over north-west Europe.

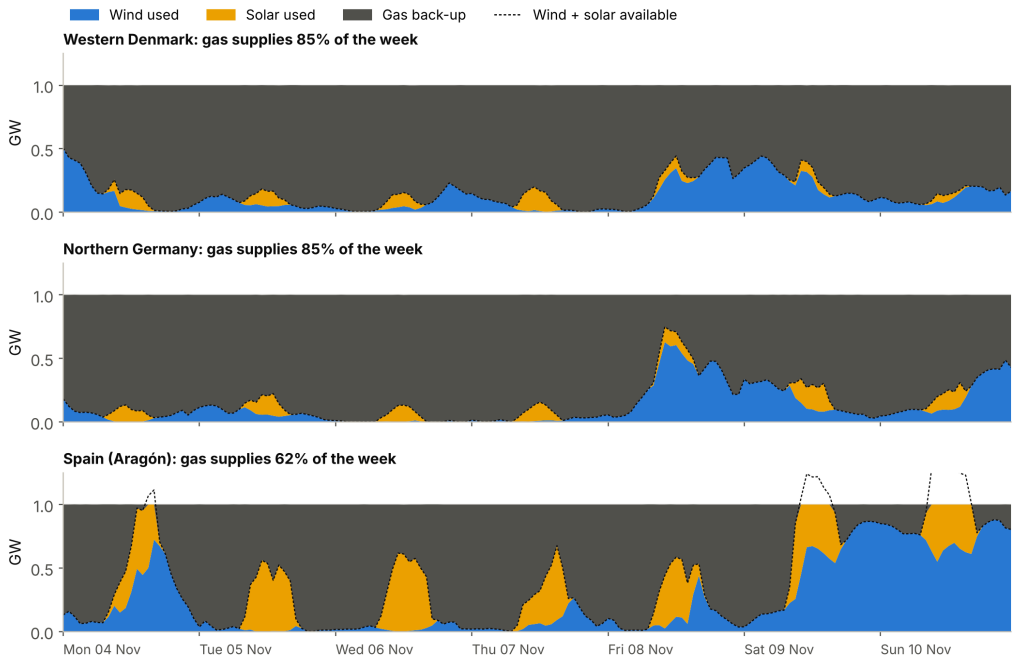


Figure 3. Hourly dispatch from 4 to 10 November 2024 for the fuel-cell designs (the gas-turbine designs have slightly more wind and solar). Gas met 85% of demand in western Denmark and 85% in northern Germany over the week; in Spain midday solar kept it to 62%. Source: sbh4 hourly model; weather from ERA5 [1].

Over the three years the back-up runs in 56%–79% of all hours, mostly at part load. Its longest uninterrupted run lasted 229–361 hours, nine to fifteen days. So the back-up must be sized for the full 1 GW, with fuel supply and maintenance arranged for long winter runs, even though it delivers only 27%–39% of its maximum annual output.

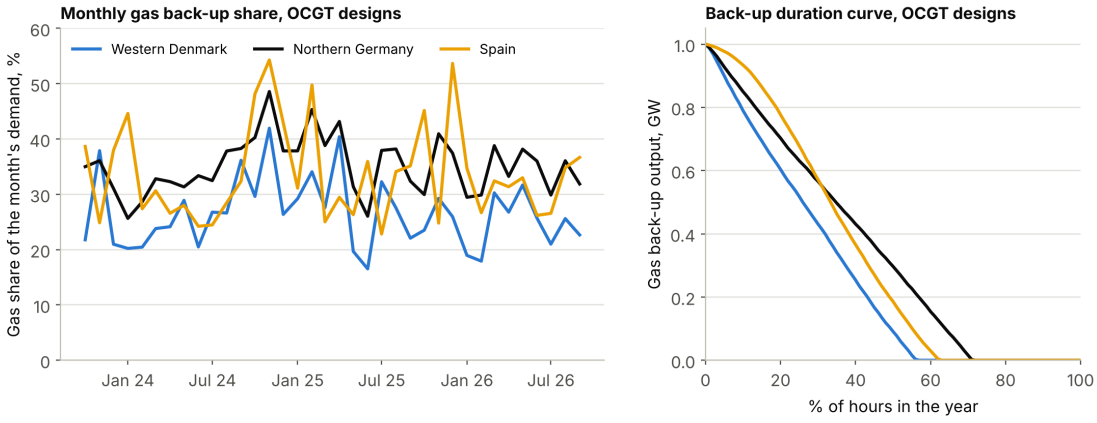


Figure 4. Left: gas share of each month's demand, OCGT designs, October 2023 to September 2026. Right: duration curve of hourly gas output over the year. The back-up runs above 90% of its rating for only 440–1,160 hours a year and at part load for thousands more. Source: sbh4 hourly model; weather from ERA5 [1].

The need for gas is not confined to winter. Its monthly share ranged from 17% to 54%; winter months (November to February) averaged 27%–38% and summer months (May to August) 25%–34%, because calm summer nights need back-up too. The highest single months were all in winter. Any technology chosen for this duty must start, stop and ramp often, and its capital cost is spread over relatively few MWh.

SECTION 6

What firm power costs

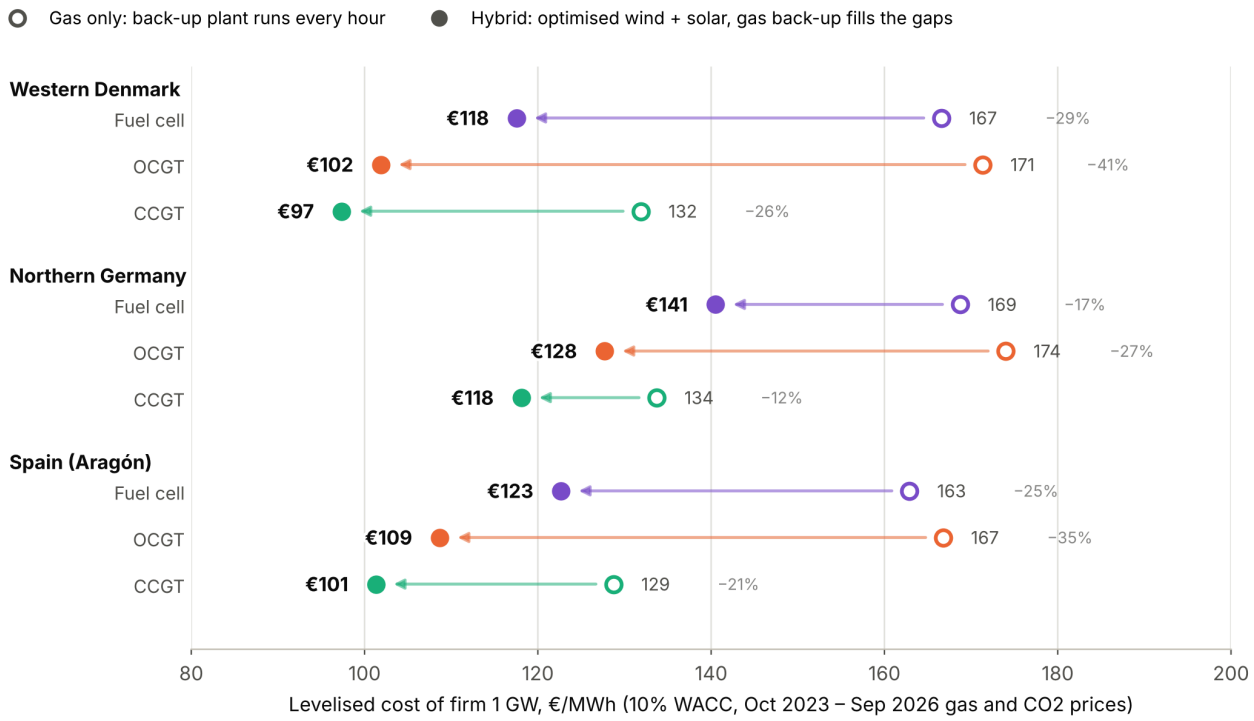


Figure 5. Cost of firm 1 GW for each back-up running alone on gas (open circles) and as part of an optimised hybrid with wind and solar (filled). The percentage is the saving from adding renewables. Source: sbh4 analysis; inputs in Table 2 and Annex B.

Adding wind and solar lowers the cost of firm power for every back-up at every site. The saving is largest for the OCGT, whose expensive gas-fired MWh are displaced most: 27%–41%. It is smallest for the CCGT in northern Germany (12%), where weaker wind meets an already efficient gas plant.

Among the hybrids, the ranking is the same at every site: CCGT cheapest (€97–118/MWh), then OCGT (€102–128/MWh), then reformer + fuel cell (€118–141/MWh). A CCGT running alone on gas (€129–134/MWh) would be cheaper than the fuel-cell hybrid in northern Germany (€141/MWh), but dearer than every other hybrid.

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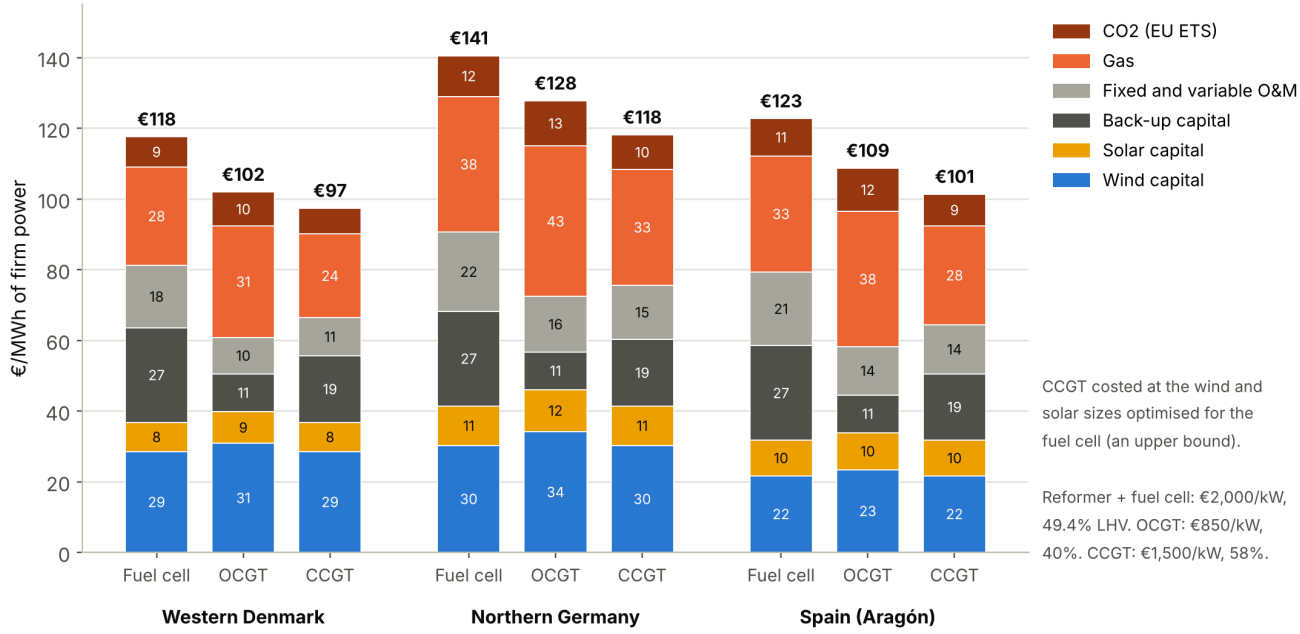


Figure 6. Cost build-up of the nine hybrids, € per MWh of firm power. Capital charges at 10% WACC; O&M includes fixed and variable costs; gas and CO2 at monthly prices, October 2023 to September 2026. Source: sbh4 analysis.

Table 6. Cost of firm power, € per MWh

Site	Back-up	Hybrid	Gas only	Saving from wind + solar	Hybrid: capital €/MWh	Hybrid: gas + CO2 €/MWh	Hybrid CO2 g/kWh
Western Denmark	Reformer + fuel cell	117.6	166.6	29%	63.6	36.4	119
	OCGT	**101.9**	**171.3**	**41%**	**50.5**	**41.0**	**134**
	CCGT	97.4	131.9	26%	55.6	31.0	101
Northern Germany	Reformer + fuel cell	140.5	168.7	17%	68.2	49.9	160
	OCGT	**127.7**	**174.0**	**27%**	**56.7**	**55.4**	**177**
	CCGT	118.1	133.7	12%	60.3	42.5	136
Spain (Aragón)	Reformer + fuel cell	122.7	162.9	25%	58.5	43.4	146
	OCGT	**108.7**	**166.8**	**35%**	**44.5**	**50.5**	**170**
	CCGT	101.3	128.7	21%	50.6	36.9	124

CCGT hybrids at the capacities optimised for the fuel cell (upper bound). At the OCGT-optimised capacities they cost €98.2–119.5/MWh, so the result is insensitive to the exact mix.

Capital charges make up 41%–57% of the cost of the hybrids. In the fuel-cell systems the back-up alone adds about €27/MWh of capital charge, against €11/MWh for the OCGT and €19/MWh for the CCGT. Gas and carbon make up €41–55/MWh of the OCGT hybrids' cost.

SECTION 7

Fuel cell or gas turbine?

The classic screening curve explains the ranking. Each back-up has a fixed annual cost per kW and a variable cost per MWh; which is cheapest depends on how many hours it runs.

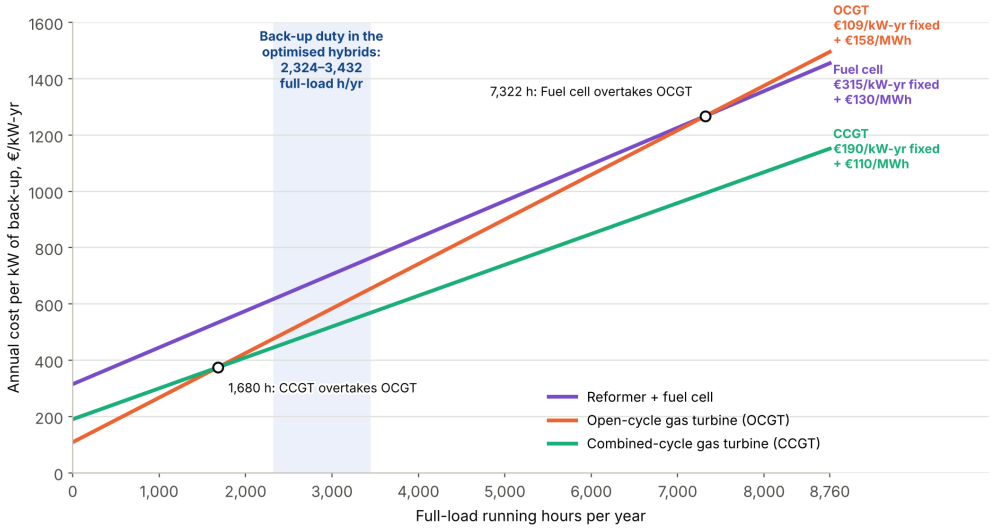


Figure 7. Screening curves: annual cost of owning and running 1 kW of back-up against full-load running hours, using average gas and CO2 prices for the three sites. The shaded band is the duty the back-up actually performs in the optimised hybrids. Sources: plant data from DEA [3], Lazard [18] and IEA [17]; gas [13, 14]; carbon [16].

The reformer + fuel cell carries €315/kW-yr of fixed cost against €109/kW-yr for the OCGT. Its efficiency saves about €28/MWh in gas, carbon and O&M, which repays the extra fixed cost only above about 7,300 full-load hours a year. In the hybrids the back-up runs 2,324–3,432 hours, so the fuel cell recovers less than half of its extra capital.

The CCGT sits between the two: €190/kW-yr fixed and €110/MWh variable. It overtakes the OCGT at about 1,680 hours and is cheaper than the fuel cell at every duty.

What would make the fuel cell competitive?

Holding everything else equal, a reformer + fuel cell would match the OCGT hybrid at an installed cost of about €1,128–1,288/kW (re-optimised in the hourly model) and the CCGT hybrid at about €753–876/kW (at the same wind and solar capacities). Dearer gas helps the most efficient plant, but not enough: even at September 2026 gas and carbon prices, the fuel cell's premium over the OCGT only narrows to €9.4–13.1/MWh.

On the other hand, the fuel cell route has strengths that this comparison does not value: the reformer produces a concentrated CO2 stream that is easier to capture than turbine exhaust, and the same fuel cell could later run on delivered hydrogen. Neither carbon capture nor hydrogen supply was modelled.

Flexibility: the hidden constraint

The model assumes every back-up can follow the hourly shortfall between 0 and 1 GW at constant efficiency. That is a fair approximation for a fleet of modern open-cycle units, less so for the others.

Table 7. Fitness of each back-up for the firming duty

	Reformer + fuel cell	OCGT	CCGT
Efficiency, capex	49.4% LHV, €2,000/kW (sbh4 assumption)	40% LHV, €850/kW	58% LHV, €1,500/kW
Start-up	Fuel cell can follow load; steam reformers are designed for steady, continuous operation	About 5 minutes to full load for an aeroderivative unit [20]; simple cycle as quick as 10 minutes [21]	Start times measured in hours for conventional combined cycles [21]
Turndown	Reformer turndown limited (not quantified here)	About 50% per unit [20]; a fleet of units covers 0–100%	Part-load efficiency falls; not modelled
Scale	Modular: above about 1 MW, cost per kW almost independent of size (Section 8)	Strong economies of scale; small units cost more per kW and are less efficient	Steam cycle favours large plant; not assessed below 1 GW
What it would take	Hydrogen buffer storage or a hot-standby reformer (not costed)	Several units, plus a spare unit (N+1) where firmness is critical	Fast-start design; suited to large projects only

Reading the ranking. On cost alone at 1 GW the CCGT wins, but conventional combined cycles start too slowly for daily cycling. The practical choice for firming is therefore between fast-starting OCGTs and a fuel cell. At 1 GW the OCGT is clearly cheaper. Section 8 shows that the ranking reverses for small projects.

SECTION 8

Scale: where the fuel cell wins

The 1 GW result does not hold at every size. Gas turbines enjoy strong economies of scale; fuel cells are built from identical modules. Below a few tens of MW, that difference reverses the ranking.

Gas turbines: big is cheap

The cost of a gas turbine plant rises much more slowly than its output. In the US Department of Energy's survey of packaged gas turbines for combined heat and power, installed cost falls from $5,200/kW at 2 MW to $1,700/kW at 25 MW, including $100–600/kW for heat recovery [22]. The US Energy Information Administration puts a 419 MW simple-cycle H-class unit at $836/kW in 2023 dollars [23]. With the heat-recovery cost removed and all costs brought to 2023, a power law fitted to these points gives a scaling index of about 0.62: doubling the size of the plant raises its cost by only 1.54 times, so cost per kW falls by about 23% with each doubling. Small turbines are also less efficient: about 33% (LHV) at 10 MW, against 40% from around 34 MW upwards [22, 23].

Fuel cells: modular and linear

A fuel-cell power plant is a repetition of factory-built modules. A current natural-gas solid oxide unit, for example, is rated at 325 kW, with a quoted cumulative electrical efficiency of 53–65% (LHV) [25]; a 10 MW plant needs about 30 of them and a 1 GW plant about 3,000. Cost per kW falls steeply up to module size (US EPA: $10,000/kW at 300 kW and $4,600/kW at 1.4 MW, 2014 $ [24]), but beyond that savings come mostly from shared site works and manufacturing volume, not from plant size. This paper uses a scaling index of 0.95 (cost per kW falls about 3% per doubling), anchored to the €2,000/kW assumed at 1 GW, and the same efficiency at every size.

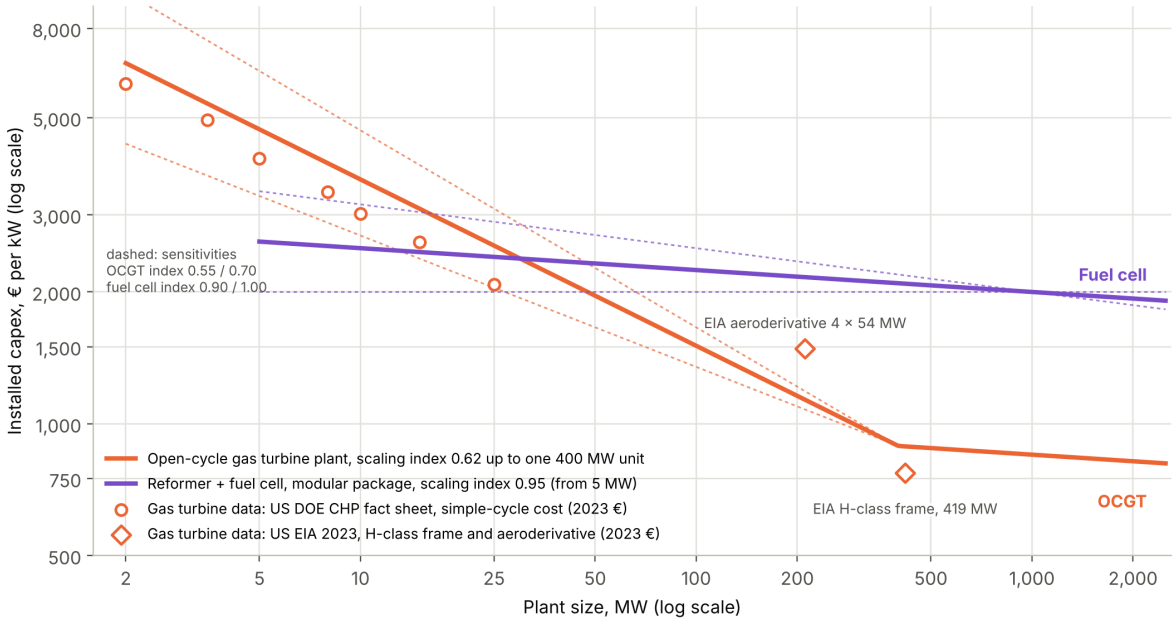


Figure 8. Installed capex per kW against plant size. Gas-turbine data: US DOE CHP fact sheet (2018; heat-recovery boiler removed; escalated to 2023 with the CEPCI) [22, 27] and US EIA (2023 $) [23], converted at the ECB 2023 average rate. Model curves in 2025 €, anchored to €850/kW (OCGT) and €2,000/kW (fuel cell) at 1 GW; the OCGT curve sits about 10–25% above the 2023 data, except for the aeroderivative plant, which costs more.

Table 8. Back-up plant characteristics and cost of firm power by project size (€/MWh)

Firm load	OCGT capex €/kW	OCGT efficiency	Fuel cell capex €/kW	DK fuel cell	DK OCGT	DE fuel cell	DE OCGT	ES fuel cell	ES OCGT	Cheaper
10 MW	3,615	33%	2,518	127	150	150	179	132	159	Fuel cell
50 MW	1,961	40%	2,323	124	118	147	144	129	125	OCGT
100 MW	1,507	40%	2,244	122	111	145	137	127	118	OCGT
200 MW	1,158	40%	2,168	121	106	144	132	126	113	OCGT
500 MW	880	40%	2,071	119	102	142	128	124	109	OCGT
1 GW	850	40%	2,000	118	102	141	128	123	109	OCGT
2 GW	821	40%	1,932	117	101	140	127	122	108	OCGT

Same wind and solar design per MW at every size (the OCGT-optimised design at each site) and same gas price, so only the back-up changes. At 1 GW the fuel-cell values are up to €0.6/MWh above Table 6, where wind and solar are optimised for the fuel cell. Fuel-cell efficiency 49.4% LHV at all sizes. Source: sbh4 analysis.

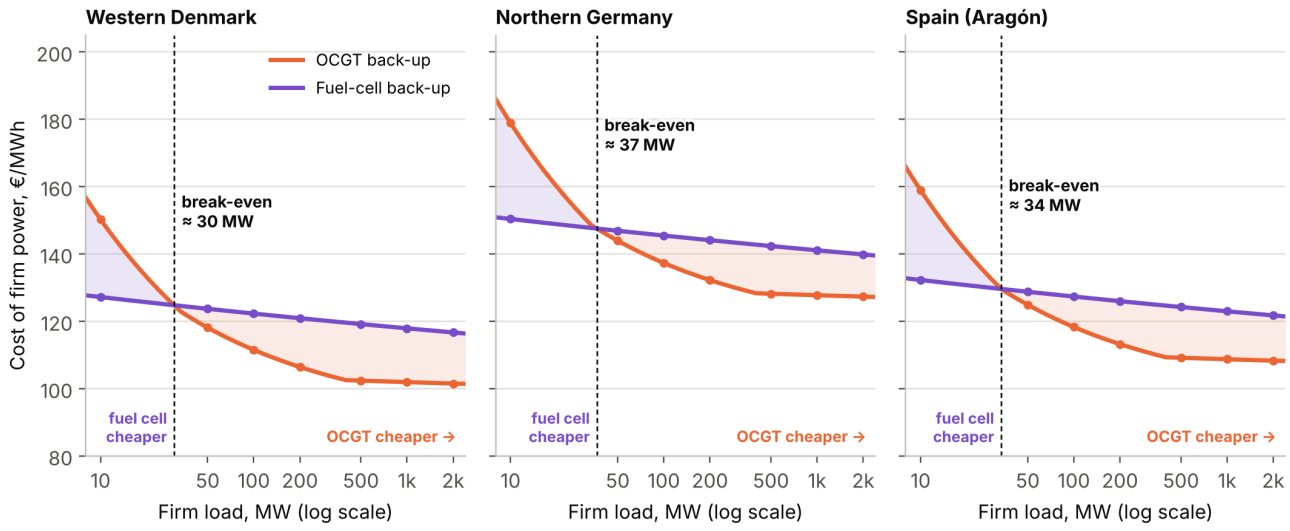


Figure 9. Cost of firm power from wind, solar and gas back-up against the size of the firm load. Shading shows which back-up is cheaper. Dots mark 10, 50, 100, 200, 500, 1,000 and 2,000 MW. Source: sbh4 analysis.

The two effects pull the same way at small scale. At 10 MW the OCGT costs about €3,600/kW against €2,500/kW for the modular fuel cell, and its gas, carbon and O&M cost per MWh is about 45% higher. The fuel cell is then cheaper by €23–29/MWh of firm power. By 50 MW the OCGT costs about €2,000/kW, has reached full efficiency and wins by €3–6/MWh; at 1 GW its lead is €13–16/MWh.

The break-even lies at about **30–37 MW** of firm load: 30 MW in western Denmark, 34 MW in Spain and 37 MW in northern Germany. It is highest in Germany because the back-up runs most there (3,078 full-load hours a year) and gas is dearest, so the fuel cell's efficiency is worth more.

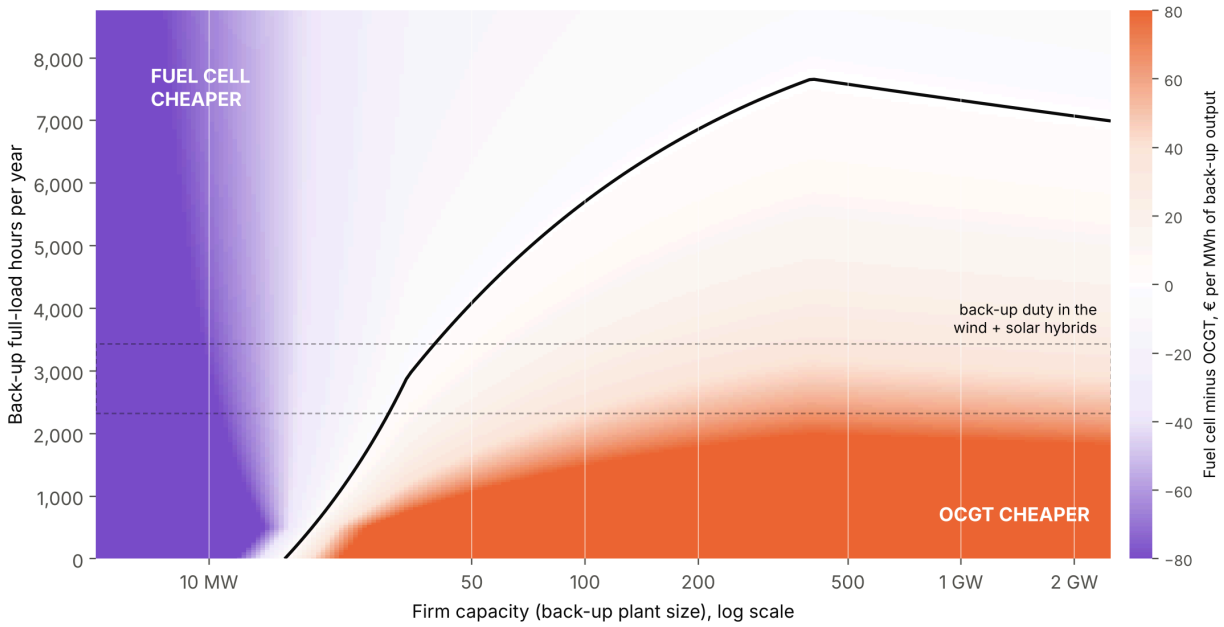


Figure 10. Which back-up is cheaper, by plant size and annual running hours, at average gas and carbon prices for the three sites. The black line is the break-even. The dashed band is the duty of the back-up in the wind and solar hybrids. Colour: cost difference per MWh of back-up output. Source: sbh4 analysis.

Running hours move the inflection point. With little or no running, the fuel cell wins on capex alone below about 16 MW. At 3,000 hours a year, typical of a renewable hybrid, it wins below about 35 MW; at 5,000 hours below about 72 MW; and at 6,000 hours below about 117 MW. Only above about 7,700 hours a year would the fuel cell's efficiency win at every size, but firming plant in a wind and solar hybrid never runs that much.

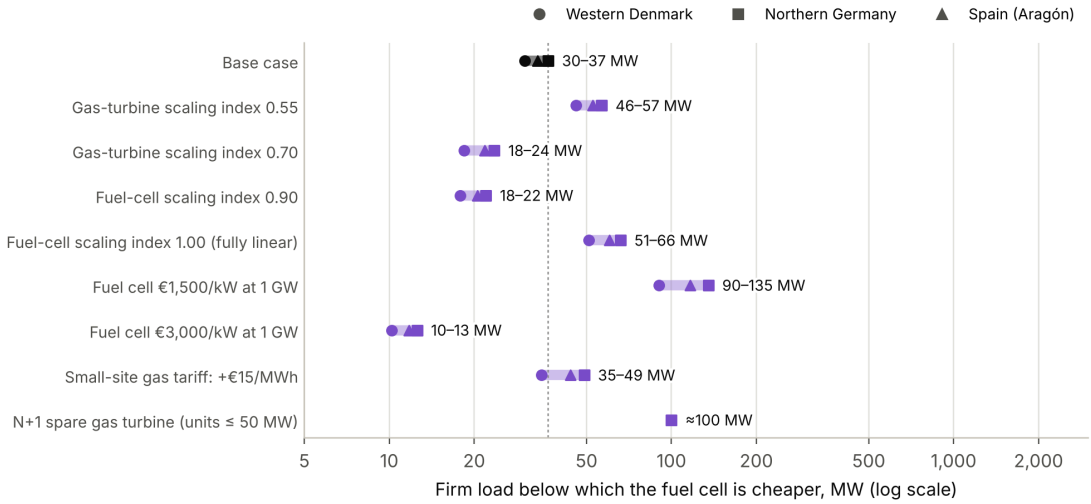


Figure 11. Firm load below which the fuel cell is cheaper, under alternative assumptions, for each site. Source: sbh4 analysis.

How robust is the inflection point?

- **Fuel-cell cost is the largest driver.** At €1,500/kW at 1 GW scale the crossover rises to 90–135 MW; at €3,000/kW it falls to 10–13 MW. For context, the US utility AEP announced in January 2026 a $2.65 billion purchase of solid oxide fuel cells as it took up an option for a further 900 MW [26]. That implies roughly $2,650–2,950/kW for the fuel cells, depending on whether an earlier 100 MW is included. The report does not say whether installation is part of the price. Installed costs today are therefore probably nearer the €3,000/kW case; the €2,000/kW base assumes further cost reduction.
- **Scaling indices.** A gas-turbine index of 0.55 (stronger economies of scale) moves the crossover to 46–57 MW; 0.70 moves it to 18–24 MW. A perfectly linear fuel cell (index 1.0) gives 51–66 MW.
- **Redundancy.** Firm supply usually needs a spare unit. With one spare gas turbine of up to 50 MW, a 10 to 50 MW project must build twice its firm capacity in turbines, while a fuel-cell plant needs only one or two spare modules (a few per cent). This alone lifts the crossover to about 100 MW. Spare fuel-cell modules are not costed.
- **Gas tariff.** Small sites connected to the distribution network pay more for gas. Adding €15/MWh favours the more efficient fuel cell and lifts the crossover to 35–49 MW.

> **Rule of thumb.** For firming wind and solar, a modular fuel-cell back-up is likely to beat an open-cycle gas turbine below roughly 30–37 MW of firm load, and up to about 100 MW where N+1 redundancy is required. Above about 50 MW without redundancy, the gas turbine's economies of scale win, and its advantage grows to €13–16/MWh at 1 GW. The crossover is most sensitive to the installed cost of the fuel cell, which should be tested against firm quotes for each project.

Caveats and scope

First, the fuel-cell chain in this paper includes a gas reformer. Modular scaling assumes the reformer is part of each package, as in solid oxide fuel cells that reform natural gas internally. A central steam reformer has its own economies of scale and would lower the crossover. Second, wind and solar are costed at utility-scale prices at every size. Small wind and solar projects cost more per kW, which raises the cost of firm power for both back-up options but does not change which one is cheaper. Combined cycles were left out of the scale analysis: the steam cycle adds cost and complexity that favour large plant, and conventional designs start too slowly for this duty.

SECTION 9

Emissions

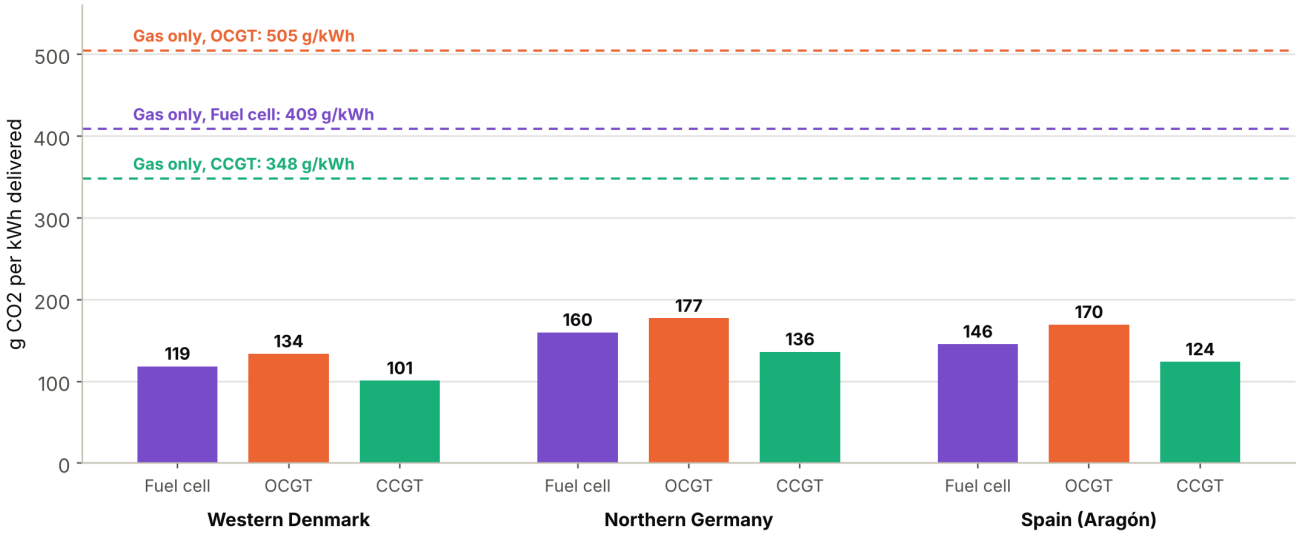


Figure 12. Direct CO2 emissions per kWh delivered, from gas combustion and reforming (0.202 t CO2 per MWh of gas, LHV). Dashed lines: the same back-up running on gas alone. Source: sbh4 analysis.

Wind and solar cut emissions by 61%–73% compared with gas-only supply from the same plant. The CCGT hybrids emit least (101–136 g/kWh), the OCGT hybrids most (134–177 g/kWh). The fuel-cell hybrids sit in between because the fuel cell's efficiency advantage is partly offset by the slightly smaller renewable build around it.

At the average EU ETS price of €72/t, carbon adds €7–13/MWh to the hybrids. A higher carbon price would favour the most efficient back-up and a larger renewable share, but it does not change the ranking between the three technologies in the range tested.

For context, even the best hybrid here emits more than a grid dominated by renewables and nuclear. Reaching very low emissions would need storage, a grid connection that can import low-carbon power, carbon capture on the back-up or back-up fuelled by biomethane or hydrogen.

SECTION 10

Economics at a fixed sale price

The levelised cost is also the break-even price: the flat price at which the plant earns exactly its 10% cost of capital. Every €10/MWh on the sale price is worth €88m a year to a 1 GW flat load.

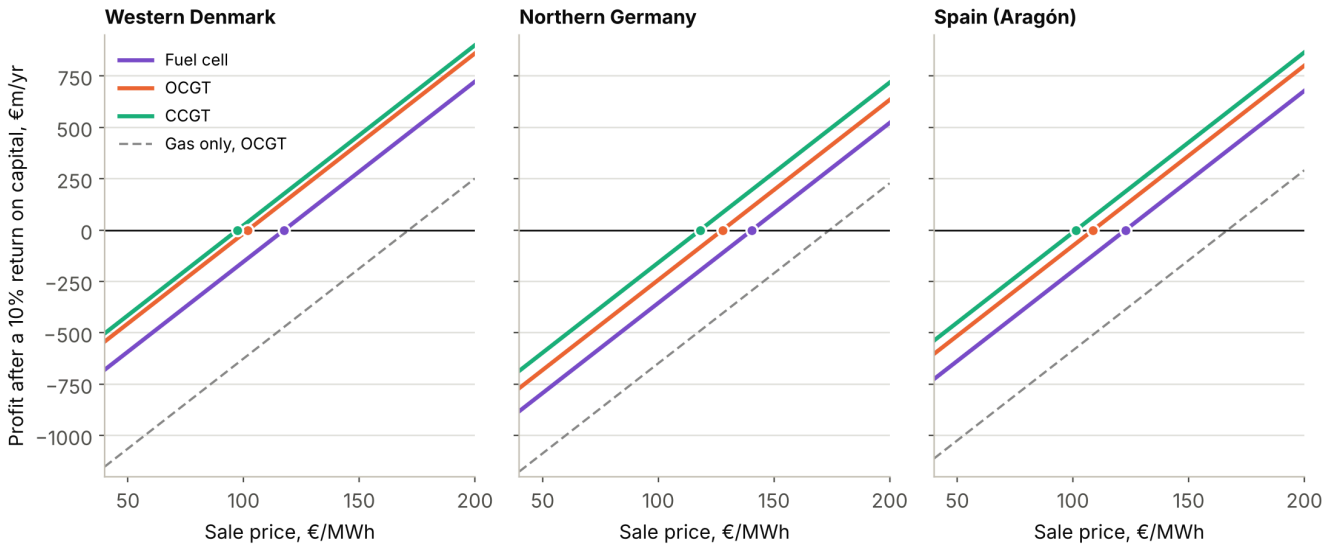


Figure 13. Annual profit after a 10% return on capital against a fixed sale price for all 8.77 TWh/yr. Dots mark the break-even price. Grey dashed: gas-only OCGT. Source: sbh4 analysis.

Table 9. Capex, break-even price, profit and payback

Site	Back-up	Capex €bn	Break-even €/MWh	Profit at €120 €m/yr	Profit at €150 €m/yr	Profit at €200 €m/yr	Payback at €150 simple, yrs	Payback at €150 discounted, yrs
Western Denmark	Fuel cell	4.95	118	21	284	723	5.9	9.3
	OCGT	**4.05**	**102**	**159**	**422**	**860**	**4.7**	**6.6**
	CCGT	4.45	97	198	461	900	4.7	6.6
Northern Germany	Fuel cell	5.33	141	-180	83	522	7.8	16.0
	OCGT	**4.55**	**128**	**-68**	**195**	**634**	**6.6**	**11.2**
	CCGT	4.83	118	17	280	718	6.0	9.6
Spain (Aragón)	Fuel cell	4.55	123	-24	239	678	6.1	9.8
	OCGT	**3.58**	**109**	**99**	**362**	**801**	**4.8**	**6.8**
	CCGT	4.05	101	164	427	865	4.7	6.6

Profit = revenue − operating cost − capital charge at 10% WACC. Payback from the annual operating margin; discounted at 10%. Pre-tax, real terms, no replacement capex.

At €120/MWh, six of the nine hybrids earn more than their cost of capital; at €150/MWh, all nine do. Gas-only supply needs €129–134/MWh with a CCGT and €167–174/MWh with an OCGT.

SECTION 11

Sensitivities

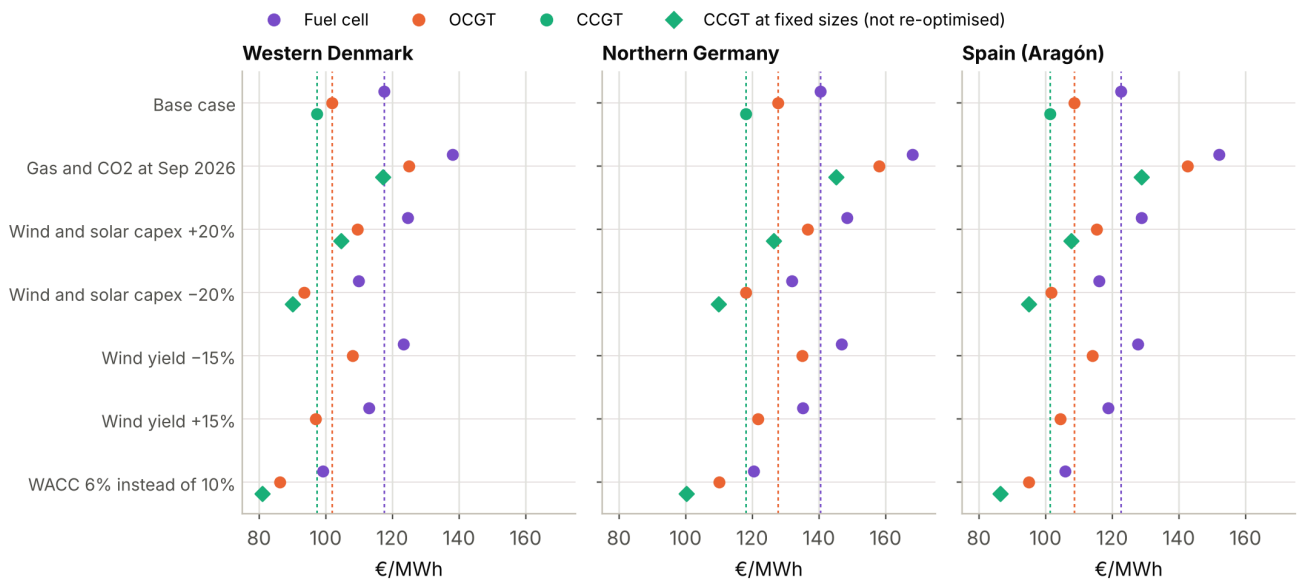


Figure 14. Cost of firm power under alternative assumptions. Fuel-cell and OCGT systems are re-optimised hour by hour for each case; CCGT values (diamonds) are at fixed capacities and are therefore upper bounds. Wind-yield cases were not run for the CCGT. Source: sbh4 analysis.

- **Gas and carbon at September 2026 prices** (gas €76–79/MWh, EUA €85/t) raise costs by €20–34/MWh. The optimiser responds by building more wind and solar.
- **Wind and solar capex ±20%** moves costs by €6–10/MWh.
- **Wind yield ±15%** moves costs by €4–7/MWh; the Spanish wind yield is the least certain input (Annex B).
- **A 6% WACC** instead of 10% lowers costs by €14–20/MWh, the largest single lever after the gas price.

At 1 GW the reformer + fuel cell remains the dearest back-up in every case, and the CCGT the cheapest in every case in which it was tested. The fuel-cell premium over the OCGT stays between €9–16/MWh.

Tornado charts: one input at a time

Figures 15 and 16 vary one input at a time between the settings shown, with the wind and solar design held at its base optimum. For this, the €2,000/kW fuel-cell chain is split into a fuel cell at €1,000/kW and a steam reformer at €650 per kW of hydrogen output, close to the IEA's USD 720/kW [17]. That is about €1,000 per kW of electricity at 65% fuel-cell efficiency. A less efficient fuel cell needs more hydrogen, and so a larger reformer, for each kW of output; the model includes this.

Holding the design fixed slightly overstates cost increases and understates savings. At 6% WACC, for example, the fixed designs cost €0.4–0.9/MWh more than the re-optimised results in Figure 14.

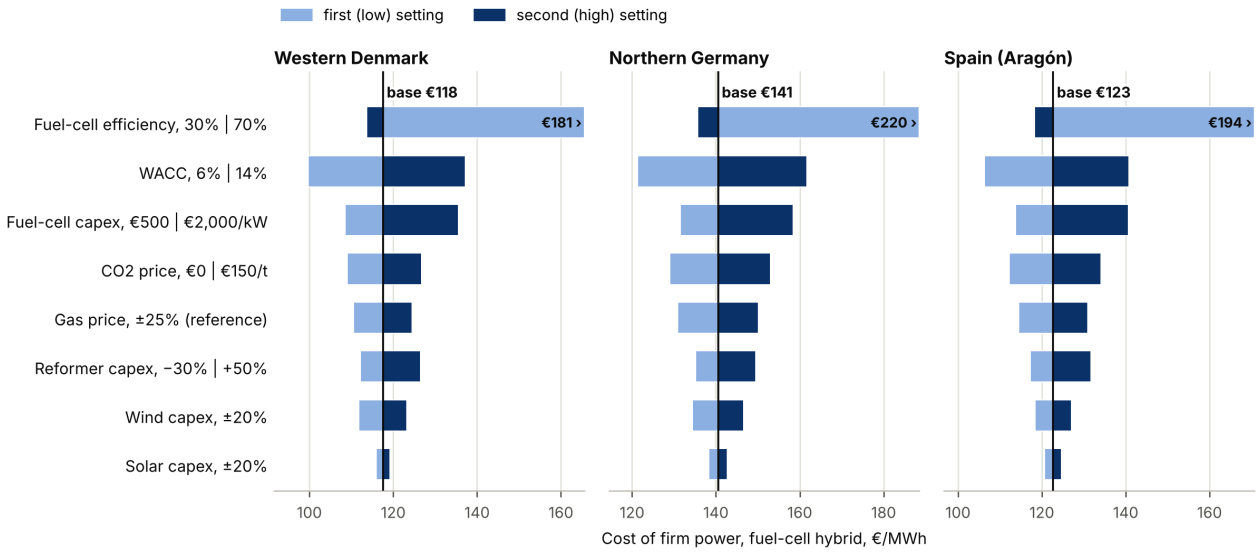


Figure 15. Cost of firm power from the fuel-cell hybrid when one input is changed. Fuel-cell efficiency is on hydrogen (65% in the base case; 30–70% gives 23–53% from natural gas with the 76% reformer). CO2 at €0 and €150/t replaces the monthly EU ETS prices (mean €72/t). Gas ±25% is added for reference. Wind and solar capacities fixed at the base optimum. Source: sbh4 analysis.

Fuel-cell efficiency has the largest and most lopsided effect. Raising it from 65% to 70% saves only €4–5/MWh, but at 30% the fuel-cell hybrid would cost €181–220/MWh. **The cost of capital comes next:** a WACC of 6% gives €100–121/MWh and 14% gives €137–162/MWh. Fuel-cell capex between €500 and €2,000/kW moves the cost from €109–132 to €136–158/MWh. Removing the carbon price saves €9–12/MWh; €150/t adds €9–13/MWh.

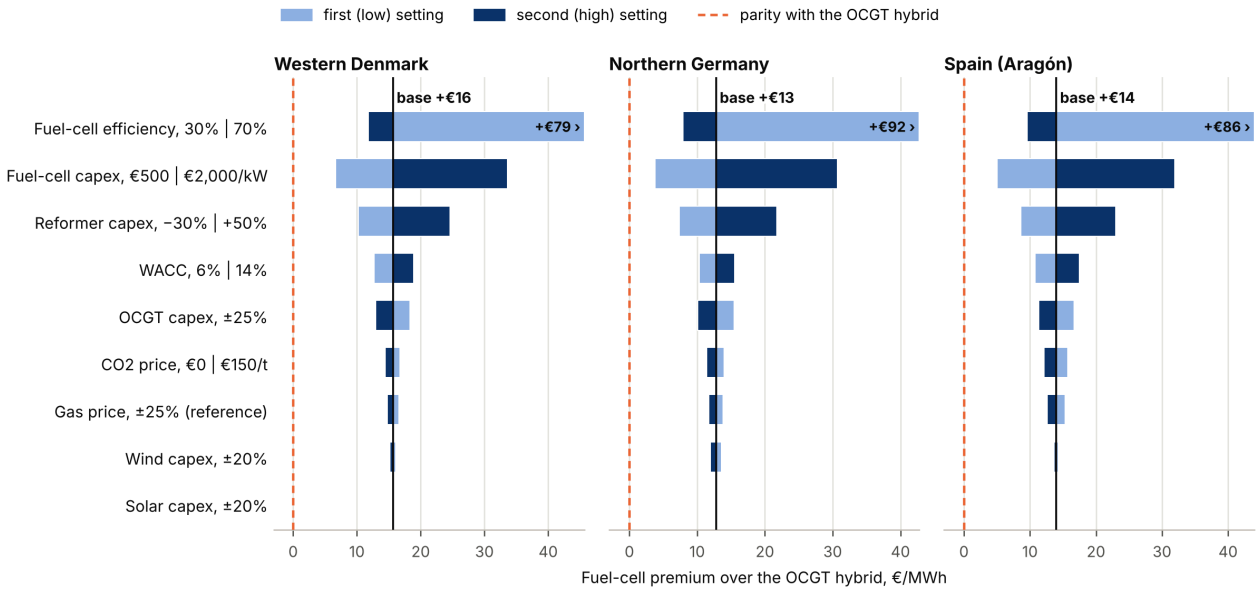


Figure 16. Premium of the fuel-cell hybrid over the OCGT hybrid when one input is changed for both. Each system keeps its own base-optimum wind and solar design. Left of the dashed line the fuel cell would be cheaper. Source: sbh4 analysis.

No single input in these ranges closes the gap with the OCGT hybrid. The smallest premiums come from a €500/kW fuel cell (€4–7/MWh) and a 70% efficient fuel cell (€8–12/MWh). Efficiency alone would have to reach 80%–91% on hydrogen, beyond any fuel cell today.

Inputs that move both systems change the premium much less than they change the cost. Cheaper capital narrows it by €2.4–3.2/MWh, because the fuel cell is the more capital-intensive back-up. A carbon price of €150/t narrows it by only €1.2–1.9/MWh: the fuel-cell hybrid emits just 10%–14% less CO2 per MWh than the OCGT hybrid, because its efficiency gain is partly offset by a smaller renewable build. Wind and solar capex hardly matter to the choice of back-up.

SECTION 12

Limitations

1. **Idealised back-up.** Every back-up follows the hourly shortfall at constant efficiency, with no start-up costs, minimum load or part-load penalty. This favours the CCGT and the reformer + fuel cell most. Sub-hourly swings in demand, such as those of an electric arc furnace, are not modelled.
2. **Fuel-cell assumptions.** The fuel-cell efficiency (65% on hydrogen LHV) and the €2,000/kW installed cost of the reformer + fuel-cell chain are sbh4 assumptions for an advanced system; published costs vary widely. Parity costs are given so readers can apply their own. A recent large purchase suggests that €2,000/kW installed is optimistic today (Section 8).
3. **CCGT optimisation.** CCGT hybrids are costed at the capacities optimised for the fuel cell, not re-optimised; their true optimum can only be lower.
4. **Off-grid.** No grid sales of surplus, no imports, no storage and no ancillary-service revenue. A grid-connected project could lower its cost.
5. **Weather period.** Three years of hourly weather, with yields calibrated to long-term references. Rarer, more severe winters would need more gas and fuel logistics, not more back-up capacity.
6. **Prices.** Real 2025 €, no inflation, tax or subsidies. Gas and carbon at historic monthly prices; future prices will differ (Section 11).
7. **Scope of costs.** Land, grid connection to the load, gas pipeline connection and fuel storage are excluded.
8. **Scale model.** Section 8 scales back-up capex with power laws, fitted to US data for gas turbines and assumed for fuel cells. Wind and solar cost per kW and the gas price are held constant, and the wind and solar mix is not re-optimised for each size or back-up. Unit sizes, redundancy rules and gas connection costs are project-specific and can move the crossover.

Talk to sbh4. sbh4 consulting supports developers, industrial energy users and investors with techno-economic modelling and investment due diligence on firm renewable power, hydrogen, e-fuels and carbon capture. The site-specific models behind this paper can be re-run for other locations, loads and technologies.

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ANNEX A

Methodology

A1 Hourly energy balance

For each hour t, wind and solar output per unit of capacity (w_t, s_t) come from the calibrated weather model. With W GW of wind and S GWp of solar, renewable supply is $R_t = W \cdot w_t + S \cdot s_t$. The back-up supplies max(0, 1 − R_t) GW and any surplus max(0, R_t − 1) is curtailed. Back-up energy is summed by month so that each month's gas and carbon price applies to the MWh generated in that month.

A2 Optimisation

Total annual cost = capital charges (capex × capital recovery factor at 10% over each asset's life) + fixed and variable O&M + gas + CO2. W and S were searched on a 0.1 GW grid from 0 to 8 GW of wind and 0 to 12 GWp of solar, for both fixed and tracking solar, then refined in 0.01 GW steps around the best point. LCOE = total annual cost ÷ 8.77 TWh.

A3 Weather calibration

ERA5 hourly data [1] for October 2023 to September 2026. Wind: a reference turbine power curve scaled to the specific power and hub height of new turbines at each site, farm smoothing, air-density correction, 10% wake and electrical losses and 97% availability; wind speeds scaled so net full-load hours match the long-run reference (Denmark 3,500 h [3]; Germany EEG reference yield × 88% quality factor × 97% [5, 6]; Spain 2,900 h, sbh4 judgement informed by [10, 11]). Solar: transposition with the Hay-Davies model, temperature losses, 8% DC losses, 98% inverter efficiency and DC/AC ratio 1.3, scaled to PVGIS-SARAH3 long-term yields [2], with 0.25%/yr degradation averaged over 30 years.

A4 Gas and carbon

Delivered gas = monthly hub price (gross calorific value) + €1.5/MWh delivery; Germany adds the Trading Hub Europe storage levy while it applied [15]. Fuel per MWh of electricity = gas price ÷ (efficiency × 0.901), converting LHV efficiency to the gross-calorific-value price basis. CO2 = 0.202 t per MWh of gas (LHV) ÷ efficiency × monthly EUA price [16].

A5 Financial metrics

Profit = revenue − operating cost − capital charge. Simple payback = capex ÷ (revenue − operating cost). Discounted payback = years until the operating margin, discounted at 10%, repays capex. All pre-tax and in real terms, with capex at year 0 and constant annual performance.

A6 Scale model (Section 8)

OCGT capex per kW: $C(P) = C_u \cdot (P/400)^{n-1}$ up to a single 400 MW unit, with n = 0.62; above 400 MW, $C(P) = C_u \cdot (P/400)^{-0.05}$, with C_u = €890/kW so that C(1,000 MW) = €850/kW. n is a least-squares fit to the DOE data [22] (heat-recovery cost removed; cost year taken as 2017, as the fact sheet gives none; escalated with the CEPCI from 567.5 to 797.9 [27]) and the EIA H-class point [23], all converted at the ECB 2023 average of $1.0813 per €. OCGT efficiency (LHV) = min(40%, 20.95% + 5.41% × ln P), fitted to the DOE efficiencies (HHV ÷ 0.901). OCGT fixed O&M is 1.8% of capex a year, as at 1 GW. Fuel-cell capex = €2,000/kW × $(P/1{,}000)^{-0.05}$, with efficiency and O&M as at 1 GW. For each size, cost of firm power = (wind and solar cost of the OCGT-optimised design + back-up fixed cost + monthly back-up energy × monthly variable cost) ÷ energy delivered. The break-even size is found by bisection.

A7 Verification

The browser-based hourly model was reproduced in Python with pvlib on sample hours (maximum difference 0.002 kW per kW); annual costs from the optimiser were recomputed independently from the monthly back-up energy and matched to within €0.01m/yr.

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ANNEX B

Assumptions register

Parameter	Value	Basis and range in the sources	Sensitivity
Wind capex	DK €1,420/kW; DE €1,650/kW; ES €1,350/kW	DEA 2025 onshore, ×1.20 to 2025 € [3]; WindGuard 2024 [4]; Spanish market range €1.2–1.5m/MW [12]	High
Wind O&M	DK €20.9/kW-yr + €2.5/MWh; DE and ES €32/kW-yr + €7/MWh	DEA [3]; Fraunhofer ISE [7]	Medium
Wind full-load hours	DK 3,500; DE 2,774; ES 2,900	DEA [3]; EEG reference yield and quality factor [5, 6]; ES judgement [10, 11]	High
Solar capex, tracker	DK €500/kWp; DE €640/kWp; ES €540/kWp	DEA 2025 [3]; Fraunhofer ISE [7]; Solar Data Atlas Q1 2026 [8]; German PV auctions 2025 [9]	Medium
Solar O&M	DK €8.7/kWp-yr; DE €14.3; ES €11.0	DEA [3]; Fraunhofer ISE [7]; Spanish market range [12]	Low
Asset lives	Wind 25 y; solar 30 y; OCGT and CCGT 25 y; fuel cell 20 y	DEA [3]; Fraunhofer ISE [7]	Low
OCGT	€850/kW; 40% LHV; €15/kW-yr + €5/MWh	DEA 40–42% [3]; Lazard $1,100–1,650/kW [18]; Fraunhofer ISE €450–700/kW [7]; LM6000 PF+ 41.3% [20]	Medium
CCGT	€1,500/kW; 58% LHV; €25/kW-yr + €4/MWh	DEA 56–58% [3]; Lazard $1,450–2,100/kW [18]; GridLab $1,770–2,260/kW [19]; Fraunhofer ISE €900–1,300/kW [7]	Medium
Reformer + fuel cell	€2,000/kW; 65% × 76% = 49.4% LHV; O&M 4% of capex/yr + €6/MWh (stacks)	Reformer efficiency IEA GHR 2025 [17]; fuel-cell efficiency and capex sbh4 assumption	High
Gas	Monthly hub + €1.5/MWh; mean €40.8–43.4/MWh	Energinet [14]; MIBGAS [13]; THE storage levy [15]	High
Carbon	Monthly EUA; mean €72/t; 0.202 t/MWh gas	EEX auctions [16]	Medium
WACC	10% real (6% sensitivity)	sbh4 assumption	High
Fuel cell and reformer split (Section 11)	Fuel cell €1,000/kW; reformer €650/kW of H2 (≈€1,000/kW of electricity at 65%)	IEA GHR 2025: USD 720/kW H2, 76% LHV, O&M 4.7%/yr [17]; split sbh4 assumption	Medium
OCGT, by size	Capex index 0.62 to 400 MW, 0.95 above (€3,615/kW at 10 MW); LHV efficiency 33% at 10 MW, 40% from about 34 MW	Fitted to US DOE CHP fact sheet [22] and US EIA 2023 [23]; CEPCI [27]; indices 0.55 and 0.70 tested	High
Fuel cell, by size	Capex index 0.95 (€2,518/kW at 10 MW; €1,932/kW at 2 GW); efficiency independent of size	sbh4 assumption; 325 kW modules [25]; EPA cost by size [24]; AEP purchase [26]; indices 0.90 and 1.00 tested	High

Sensitivity: effect on the headline cost of firm power or, for the two rows by size, on the break-even size. Real 2025 €; 2020 € values inflated by 1.20 where noted.

ANNEX C

References and disclaimer

Disclaimer. This white paper is a techno-economic analysis based on public data and the assumptions set out above. It is not investment, legal or tax advice. Results depend on site, technology, market and financing conditions that will differ for any real project. Readers should carry out their own due diligence before any decision.

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Stephen B. Harrison is the founder and managing director of sbh4 GmbH in Germany. His work focuses on decarbonisation and the reduction of greenhouse-gas (GHG) emissions. E-fuels, bio-fuels, hydrogen, ammonia, long-duration energy storage (LDES) and CCU/S are the fundamental pillars of his consulting.

Stephen has extensive investment due-diligence advisory experience in the energy and clean-tech sectors. Private equity firms, investment fund managers and green-tech start-ups are regular clients. He also supports operating companies in their mission to decarbonise their scope 1, 2 and 3 GHG emissions, and helps start-ups scale up successfully through development plans aligned to market needs.

In 2023, Stephen evaluated seven CCTUS, hydrogen and e-fuels submissions to the European Commission's Third Innovation Fund. In 2025 he assessed seven Innovation Fund applications for e- and bio-methanol production and, in 2026, six large-scale bio-SAF and e-SAF projects. In each of these years the fund allocated more than €2 billion to large-scale decarbonisation projects in Europe. In 2024, 2025 and 2026 he also supported the European Commission with venture-capital investment due diligence, and assessed 15 Horizon grant applications and more than 30 Marie Curie Post Doctoral Network and Doctoral Fellowship applications.

Stephen has served as international expert and team leader for three Asian Development Bank (ADB) projects related to CCU/S and renewable hydrogen deployment in Pakistan, Palau and Viet Nam. He has also supported the IFC and the World Bank on e-fuels and green hydrogen strategy development projects in Namibia and Pakistan, and on project evaluations in Paraguay and India.

With a background in industrial and specialty gases, including 27 years at BOC Gases, The BOC Group and Linde Gas, Stephen has intimate knowledge of e-fuels, hydrogen, ammonia and carbon dioxide from commercial, technical and operational perspectives. For 14 years he was a global business leader in these FTSE 100 and DAX 30 companies.

As a member of the H2 View (2020–26) and gasworld (2018 to present) editorial advisory boards, Stephen has advised the direction of leading hydrogen-focused international publications for more than six years. Through H2 View, World Hydrogen Leaders and Sustainable Aviation Futures he has led masterclasses on hydrogen, SAF and hydrogen derivatives in virtual and live sessions. He chaired the e-fuels and hydrogen propulsion track at the Hydrogen Technology Exhibition in 2023 and 2024, and has supported the event as an Advisory Board member since early 2025.

WHITE PAPER · NOVEMBER 2026

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