ENERGY · PAPER 04

Electricity Supply through the Transition

The evidence on generation procurement and fuel security through the transition.

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Households and industry need enough electricity through the transition, not only a credible fleet at the end of it. Delayed nuclear and networks can leave gas stations carrying far more annual generation and fuel demand than a reserve label suggests. Decisions on plants, equipment and fuel resilience must therefore follow the same dated supply model.

We will release generation commitments in tranches against coherent demand pathways, the inherited project register and nuclear delivery. Extend suitable existing plant, procure replacement gas and start nuclear scale-up in parallel. Preserve high-demand, slower-nuclear security options; compare further usable renewable output and other alternatives before making firm orders.

UK Electricity Market Reform permits new wind and solar to compete for long-term price-stabilising contracts from year one. This paper separates the inherited benchmark, prospective pre-cutoff awards and additional competitive purchases. Programme Annex Appendices A–C govern common rules; Appendix E records the status of the numerical assumptions.

The modelling in this paper uses calendar years, because the demand pathways, retirements and contracts it draws on are dated. It assumes the programme begins in 2029. Elsewhere the programme is set out in years from taking office, and the model should be re-run against the position actually inherited whenever the programme begins.

Demand pathways and the statistical baseline

Use Great Britain demand and supply consistently for procurement. DUKES describes UK outturn and has a different perimeter; it provides scale context rather than a direct subtraction from GB demand. [1–4]

UK ELECTRICITY IN 2025	TWH
Domestic gross generation	293.6
Gas	93.2
Wind	86.4
Bioenergy	41.0
Nuclear	35.9

UK ELECTRICITY IN 2025	TWH
Solar	20.1
Hydro	5.4
Demand including system uses and losses	323.0
Final customer consumption	275.5

Source [1]. The generation categories do not exhaust total generation. Storage discharge recycles charging electricity and is excluded from primary supply.

GB DEMAND TWH	2030	2035	2040	2045	2050
Ten Year Outlook 2026	324	385	—	—	—
Falling Behind	324	373	434	504	559
Holistic Transition	339	433	564	654	705
Electric Engagement	345	450	617	724	785
Hydrogen Evolution	335	464	594	733	797

Sources [2–4]. Demand is rounded from ED1 totals, including relevant networked electrolysis and network losses. Use Holistic Transition as the coherent long-term reference comparator and Falling Behind as the low-demand case. Cross all pathways with every nuclear ramp below.

NESO's three net-zero pathways are conditional designs; Falling Behind misses those targets. Their midpoint is not a probability-weighted forecast. Repealing mandatory electrification drivers may lower demand relative to those pathways, while industrial recovery and computing expansion may raise it. Transport and Heat Demand defines the package's own demand case for supply planning; Falling Behind is not a forecast of this policy package. [19]

Keep the Ten Year Outlook 2026 as a separate near-term comparator. Joining its 385 TWh in 2035 to Holistic Transition's 564 TWh in 2040 gives a 179 TWh rise. The coherent Holistic Transition rise is 131 TWh, from 433 to 564; 48 TWh of the joined rise is a baseline change. Retain the joined case only as an identified sensitivity.

Renewable inheritance and future procurement

Reconcile the inherited fleet project by project: award and signing, investment decision, delivery conditions, consent, connection, operation, support expiry, useful life and repowering. Separate awarded or offered, signed, under-construction and operating capacity. Match re-bids to their original projects so capacity is counted once. Honour valid pre-cutoff contracts even when generation begins later. [5]

WIND AND SOLAR OUTPUT	2030 TWH	2035 TWH
Offshore wind	131.3	211.6
Onshore wind	49.9	61.9

WIND AND SOLAR OUTPUT	2030 TWH	2035 TWH
Solar	43.2	61.9
Combined	224.5	335.4

Source [8], GB connection categories excluding non-networked offshore supply. The 225 TWh benchmark rounds the 2030 outlook; it is not a verified contracted cohort. The 335 TWh 2035 outlook includes further development whose award status must be reconciled.

The Climate Change Committee's pipeline assessment reaches about 32 GW offshore wind by 2030, 36 GW by 2031 and 37 GW by 2032 on timely completion. That offshore figure does not establish 225 TWh of all wind and solar output in 2030. Existing and contracted projects, including AR4 re-bids, AR6 and AR7, must be reconciled with their commissioning and connection dates. [17]

Track AR8–AR10 and any additional award made before the cutoff in year one, including any round held in the first months in office. AR8 is in progress; later rounds and volumes remain prospective. Its indicative timetable places results between 27 November 2026 and 17 February 2027, with signing extending to 17 March in the longest case. Refresh actual dates and contract-specific delivery years at each review. [18]

The base screen assumes 225 TWh wind and solar in 2035, then 210, 190 and 175 TWh in 2040, 2045 and 2050. These are survival sensitivities pending the asset register. Flat 225 TWh and stronger erosion to 125 TWh in 2050 remain alternatives. Include late inherited construction and repowering only once; use delivered output after weather, outages and curtailment.

New wind and solar can compete for energy contracts or use merchant and bilateral routes. Bid eligibility does not assume awards. Add a project to the procurement supply case only when its incremental output, delivery and connection are credible. Sources [6–7] describe commercial routes; the screen below exposes the value of extra supply without presuming it.

Inherited capacity and retirement exposure

GB OPERATING CAPACITY GW	2026	2030	2035
Offshore wind	17.0	33.6	58.6
Onshore wind	16.4	22.6	33.1
Solar	24.7	43.8	68.8
Nuclear	6.1	3.7	4.6
Gas excluding CHP	35.4	34.5	29.9
Gas with CCS	0.0	0.0	0.9
Hydrogen generation	0.0	0.0	0.9
Batteries	10.9	24.6	35.6
Long-duration storage	2.8	2.8	7.7

Source [8]. 2026 is modelled. Combined heat and power is excluded from the dedicated-gas row; storage is capacity to shift energy. The outlook is not a confirmed investment register. Maintaining a 35 GW gas comparator would require about 5.1 GW more net capacity than the 2035 outlook; extensions, refurbishment and other projects can change that gap.

Rebaseline nuclear retirement and project dates on taking office. EDF's July 2026 extension takes Heysham 1 and Hartlepool to March 2030; Heysham 2 and Torness share that expected end date. Hinkley Point C's first unit is scheduled for 2030; Sizewell C targets the mid-to-late 2030s. Wylfa's development contract precedes final investment approval. Count each inherited contribution once while available. [9–12,16]

Use station condition, owner decisions and credible extension works rather than a universal closure age. Begin condition assessments and owner tenders on taking office for an initial five-year gas extension; subsequent extension requires another inspection and paid overhaul. SSE has assessed older assets as capable of operating to at least 2035; failure to win one auction does not establish closure. [13–14]

Nuclear share and required total fleet

Retain the ambition for around 60% nuclear within twenty years, and compare a 40% portfolio under common assumptions in the Generation paper. Size total operating capacity to the demand case and availability, including credible inherited assets once.

2050 DEMAND TWH	60% OUTPUT TWH	GW AT 90%	GW AT 80%
Falling Behind 559	335.4	42.5	47.9
Holistic Transition 705	423.0	53.7	60.4
Electric Engagement 785	471.0	59.7	67.2
Hydrogen Evolution 797	478.2	60.7	68.2
700 TWh sensitivity	420.0	53.3	59.9
800 TWh sensitivity	480.0	60.9	68.5

Capacity arithmetic: nuclear output = GW × 8.76 × annual capacity factor. Three public proving units plus twelve 470 MW repeat options total 7.05 GW and 55.6 TWh at 90%; this opening tranche covers only part of the eventual fleet.

TOTAL OPERATING NUCLEAR GW	2035	2040	2045	2050
Slower delivery	5	12	25	40
Reference ramp	10	22	40	53.3
Faster larger programme	12	28	46	60.9

Cross these total-fleet trajectories with every demand pathway. The slower ramp is the procurement security stress; the accelerated programme remains the delivery objective. No ramp is inherently paired with one demand case. At 2050 the slower 40 GW fleet supplies 56.4% of Falling Behind demand, below

the 60% ambition. Appendix E records ramp status and the need for named sites, retirements and validated throughput.

REFERENCE GROWTH INTERVAL	NET ADDED GW	470 MW EQUIVALENTS PER YEAR
2035 to 2040	12.0	5.1
2040 to 2045	18.0	7.7
2045 to 2050	13.3	5.7

Gross construction must also replace retirements. Secure design maturity, supplier slots, site starts, labour, commissioning and energisation against the authorised programme. Track each separately so a factory delivery is not counted as operating electricity.

Annual gas generation across the scenario grid

SCENARIO	NUCLEAR RAMP	2035	2040	2045	2050
FB	Slower delivery	99.2	120.0	107.5	59.3
FB	Reference ramp	59.8	41.2	0.0	0.0
FB	Faster larger programme	44.0	0.0	0.0	0.0
HT	Slower delivery	159.2	250.0	257.5	205.3
HT	Reference ramp	119.8	171.2	139.3	100.4
HT	Faster larger programme	104.0	123.9	92.0	40.5
EE	Slower delivery	176.2	303.0	327.5	285.3
EE	Reference ramp	136.8	224.2	209.3	180.4
EE	Faster larger programme	121.0	176.9	162.0	120.5
HE	Slower delivery	190.2	280.0	336.5	297.3
HE	Reference ramp	150.8	201.2	218.3	192.4
HE	Faster larger programme	135.0	153.9	171.0	132.5

Table units are TWh of gas-fired electricity. FB = Falling Behind; HT = Holistic Transition; EE = Electric Engagement; HE = Hydrogen Evolution. Reproduce gas output as max(0, demand + extra storage losses + net exports − wind and solar − nuclear − other output − coal). The common screen uses 15 TWh other net output, 10 TWh additional storage losses, zero annual net trade and 4.38 TWh coal. Appendix E records these chosen inputs.

For 2040, the reference nuclear ramp gives 41.2–171.2 TWh gas electricity between Falling Behind and Holistic Transition. Slower nuclear raises those results to 120.0–250.0 TWh. Electric Engagement with slower nuclear requires 303.0 TWh. These combinations justify staged procurement and paid equipment options rather than an immediate order for the largest fleet.

The coherent Holistic Transition reference requires about 119.8 TWh gas electricity in 2035; the separate 385 TWh near-term comparator requires 71.8 TWh under the same supply assumptions. This difference is demand, not a change in assumed construction.

Inherited awards and additional renewable sensitivities

INCREMENTAL OFFSHORE SENSITIVITY	ANNUAL OUTPUT AT 45%	2035 THERMAL NEAR-TERM COMPARATOR	2035 THERMAL HT
0 GW	0.0 TWh	76.2 TWh	124.2 TWh
5 GW	19.7 TWh	56.4 TWh	104.4 TWh
10 GW	39.4 TWh	36.7 TWh	84.7 TWh

Thermal is the residual before coal allocation. A hypothetical incremental 10 GW from inherited AR8 onwards reduces the 2035 near-term comparator from 76.2 to 36.7 TWh, and coherent Holistic Transition from 124.2 to 84.7 TWh. These additions must be outside the benchmark, completed and connected; 45% capacity factor precedes curtailment and is a sensitivity, not an award forecast.

2040 HT CASE	GAS ELECTRICITY TWH	GAS FUEL TWH AT 58%	35 GW UTILISATION
Reference 22 GW nuclear	171.2	295.1	55.8%
Reference plus 60 TWh demand	231.2	398.6	75.4%
Slower 12 GW nuclear	250.0	431.1	81.5%
Slower plus 60 TWh demand	310.0	534.5	101.1%
Faster 28 GW nuclear	123.9	213.6	40.4%
Reference plus 40 TWh commercial renewables	131.2	226.2	42.8%

AI is already present in NESO modelling: the 2026 outlook includes about 22 TWh data-centre demand in 2035. LSE CETEx uses a stylised 10 GW at 90%, equivalent to 78.8 TWh, and a 20 GW high case. The flat additional 60 TWh stress tests a higher demand envelope, with included demand reconciled first; it is not added twice or treated as an AI forecast. [2,15]

Incremental usable renewables reduce the gas-energy residual approximately one for one under these fixed annual assumptions. Their contribution to scarce-hour capacity is assessed separately. Generation and the North Sea paper must use the same scenario identifiers before claiming lower gas or import requirements.

Fuel security and dependable capacity

2040 DEMAND WITH SLOWER NUCLEAR	GAS ELECTRICITY TWH	POWER-STATION GAS FUEL TWH
Falling Behind	120.0	206.9
Holistic Transition	250.0	431.1
Electric Engagement	303.0	522.4

2040 DEMAND WITH SLOWER NUCLEAR	GAS ELECTRICITY TWH	POWER-STATION GAS FUEL TWH
Hydrogen Evolution	280.0	482.8
HT plus 60 TWh demand	310.0	534.5

Fuel figures cover power stations only. Add heating and industrial demand in the joint gas-system model. Preserve fuel, terminal, pipeline, storage and fallback options against high demand with slower nuclear, with additional usable domestic output and other generation treated as relief. Test prolonged cold and low wind, nuclear outages, import interruption and storage depletion through annual consumption and peak daily deliverability.

A 35 GW gas fleet cannot supply the combined 310 TWh case even at continuous nameplate output. Maintenance, outages and derating tighten the usable limit further. Added gas capacity supplies headroom but does not itself reduce fuel consumption: 171.2 TWh needs 55.8% utilisation of 35 GW or 48.9% of 40 GW.

GB UNDERLYING WINTER PEAK	2026	2030	2035
GW from 2026 outlook	60.5	64.2	72.5

Source [2]. Use the underlying average-cold-spell peak within a consistent hourly model. Include weather correlation, planned and forced outages, common-mode nuclear failures, storage energy and replenishment, demand response, interconnector scarcity correlation, regional networks and fuel delivery. Report loss of load expectation, expected unserved energy and adverse-event severity against the published standard.

Reconcile dedicated data-centre generation, grid purchases and backup so firm supply is not reserved twice. Large loads that bring their own firm capacity reduce the public requirement one for one; count that capacity once and track its equipment orders with the public programme, as set out in UK Electricity Market Reform. Short-duration storage supplies its tested duration and requires charging; it cannot cover a week-long energy deficit by its power rating. Flexibility counts with credible duration, price, rebound and performance.

Coal and other thermal options

COAL FLEET ASSUMPTION	COAL TWH	2040 HT REFERENCE GAS TWH
No coal	0.0	175.6
2 GW at 25%	4.4	171.2
2 GW at 50%	8.8	166.8
5 GW at 50%	21.9	153.7
5 GW at 70%	30.7	144.9

Procure the first coal station for regular generation and release further stations where the system plan justifies them. The chronological model’s planning illustration has four 2 GW stations with mixed regular and balancing roles. Increasing nuclear output can move capacity progressively into reserve. The annual

tables' 2 GW at 25% remains a separate arithmetic comparator; do not add it to the chronological fleet or interpret it as the new fleet's dispatch commitment.

Assess dependable capacity and annual energy separately. Compare refurbishment, gas, nuclear, storage, flexible demand, renewables and credible imports under Appendix C's carbon tax settlement and Appendix E's release test. The tables retain their stated physical assumptions: the tax transition changes costs and may change demand, dispatch and investment, but does not mechanically change the TWh balances. Rebase these pathways when evidence supports a change; do not infer new gas or coal orders solely from the lower carbon charge.

Annual decisions and gas tranche release

Chronological delivery planning case

Size procurement to the three-hour loss of load expectation standard, with interconnectors credited at NESO's published de-rating factors. The explorer's Official standard setting replays each year with random plant outages and resizes the whole new gas fleet to that standard, within constrained delivery and with selective five-year retention. Test all three demand pathways, annual construction and retirements, hourly weather, trade, flexible electrolysis, fuel use and cost. Stronger retention, faster delivery and a tight equipment market are sensitivities, not secured manufacturer allocations.

The constrained illustration commissions at most two 920 MW combined-cycle stations a year after a five-year lead, 1.5 GW a year of engines and 0.9 GW a year of open-cycle turbines, within 4.24 GW a year combined. Orders begin on taking office. Supplier offers, connections, labour and fuel must establish executable quantities; annual reviews revise future tranches without inventing earlier orders.

At central demand the standard is met in every year with one new combined-cycle station, 225 engine blocks of 100 MW and 42 open-cycle units of 300 MW by 2050; the worst year is about 2.6 hours. Low demand needs no new combined-cycle plant, 157 engine blocks and 21 open-cycle units. High demand keeps 23 combined-cycle stations and still exceeds the standard in 2031–36 and 2040–41, because equipment cannot be delivered sooner. In a tight equipment market, with combined-cycle plant at £1,500/kW and seven years to power and engines limited to 1 GW a year, the central case keeps all 30 combined-cycle stations and exceeds the standard in 2031–36. These counts are model candidates, not procurement commitments.

Treat cover for a prolonged cold, still spell beyond the standard as a separate resilience reserve. The earlier planning case, sized against historical-weather and synthetic-stress screens, costs about £20.6bn more over 2030–2050 at central demand and £31.7bn more at low demand, yet passes the synthetic stresses in only four of 21 years at central demand. Government decides whether to buy such a reserve; it is not part of the standard.

Coal is illustrated with up to 4 GW regularly committed through 2044, the remainder scheduled economically, and reserve operation from 2045. This switch is a model sensitivity; policy permits station-specific roles and dates. Two additional stations delivered earlier reduce the central 2036 synthetic-stress unserved energy from about 4.00 to 2.52 TWh, but do not close it. Extra coal remains a conditional security option.

The model reports reliability-standard results, normal-weather shortfalls and synthetic stresses separately. The high-demand constrained case retains gaps; no programme is described as meeting every year. Annual reviews must identify the residual capacity, equipment, connection and fuel gap, then publish an executable remedy or escalation. A lower subtotal for an under-supplied case is not an equal-service saving.

DECISION DATE	REQUIRED ACTION
Inherited-fleet assessment on taking office	Verify asset condition, signed contracts, demand pipeline, fuel resilience and network dates. Reserve justified equipment or site options with disclosed costs.
By the middle of year one, then annually	Publish coherent demand-by-nuclear grid, forward adequacy, project probabilities, fuel stresses and the next release decision.
When forward demand follows HT or higher and nuclear follows slower ramp	Release the next gas tranche or award qualifying renewable energy where it provides the needed service; compare refurbishment, nuclear acceleration and other deliverable options.
Before each commitment	Test what equipment can be obtained: supplier slots, global backlogs and inventories, delivery dates and prices; choose the technology accordingly. Look ahead by plant, equipment and connection lead times plus a margin. Price options, cancellation, fuel, carbon and public exposure; use the shared release test.

The trigger is the forward gap and forecast security breach, not a retrospective shortage or a single observed demand year. Act earlier than the annual date when lead times require it. Publish a funded remedy or escalation if the normal auction cannot secure the standard. Lower demand, faster nuclear and incremental inherited or commercial supply reduce subsequent commitments. Where forecast demand outruns the firm capacity that can be obtained, phase firm connections for large new loads to the pace at which firm capacity is delivered, through the reformed connections process.

Separate availability from dispatched energy, with explicit fuel, efficiency and failure terms. Preserve falling utilisation as nuclear arrives rather than guarantee unnecessary gas burn. Treat the 35 GW figure as a comparator, not a cap or construction order. NESO owns the technical assessment; the purchaser contracts services; owners deliver; government settles policy and funding.

Model reproduction and completion

Demand uses ED1 2026 total system demand and ED1 2025 GBFES System Demand Total, converting GWh to TWh. Supply uses ES1 2026 aggregated by Type and Variable across relevant connection categories, converting MW to GW and excluding non-networked offshore output and CHP from the dedicated-gas comparator. [2–4,8]

The grid uses rounded source demand and unrounded arithmetic: nuclear output = GW × 8.76 × 0.9; coal output = 2 × 8.76 × 0.25 = 4.38 TWh; gas fuel = gas electricity ÷ 0.58. Calculate each milestone independently. Additional offshore output = GW × 8.76 × 0.45, subtracting only incremental usable supply. Display rounding occurs last.

Maintain the project cohort and chronological model alongside these reproducible annual arithmetic screens. The explorer now carries retention, construction, retirements, hourly supply screens, a probabilistic proxy for the three-hour standard, fuel and partial cashflows through 2030–2050. Validate

engineering availability, supplier allocations, regional networks and NESO's full probabilistic assessment before fixing procurement quantities. The accompanying methods, sources and assumption register records estimates and limitations; Programme Annex Appendix E is the shared policy control register.

What this paper does not claim

These annual energy screens do not establish hourly reliability, executable construction dates, financeable orders or guaranteed renewable output. The nuclear ramps, survival assumptions, AI stress and fuel efficiency are declared sensitivities. No unawarded round, optional plant or experimental shale supply is counted as an inherited commitment.

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Source versions and added references checked 12 October 2026. Scenario inputs are recorded in Programme Annex Appendix E. Read with UK Electricity Market Reform, Generation Expansion and Mutual Finance and Domestic Fuel Supply Oil Gas and Coal.