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E·S·R·C ECONOMIC & SOCIAL RESEARCH COUNCIL

Transition to a low carbon electricity market and needed reforms

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EDF Energy Meeting

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http://www.electricitypolicy.org.uk

Outline

- Challenge for GB power market
- Suitable market design
  - Congestion management, plant operation
  - Location/type of investment
- Transition
  - Fair treatment of existing assets
  - avoid discouraging wind
- Consequences of large wind share

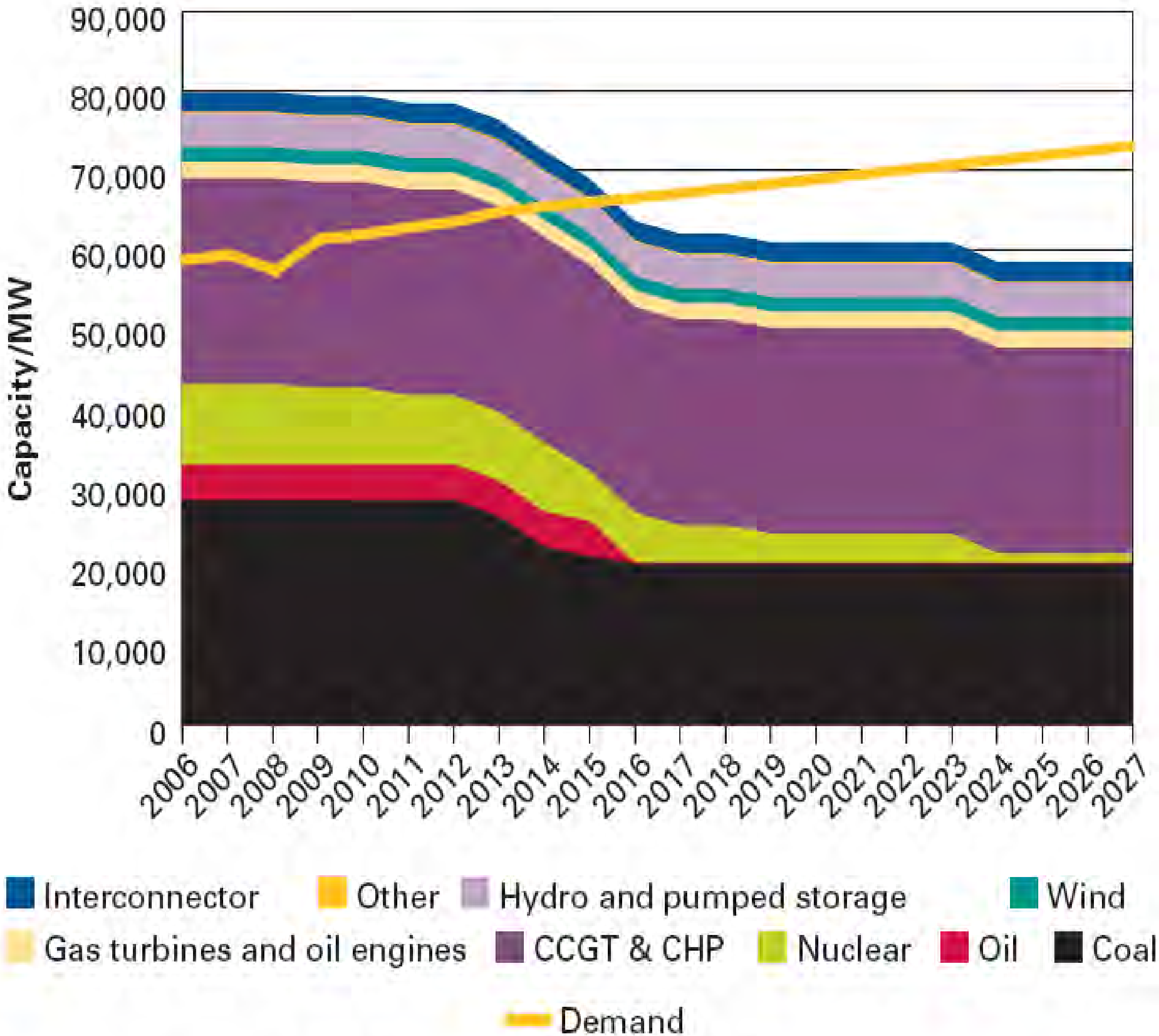
Energy market developments

- Huge oil price volatility: $145-40/bbl
  - contract price of gas linked to and lags oil
  - UK gas prices 20p/th-110, now 60p/th
  - coal prices $50-200/t; now $100/t
  - 2nd period EUA prices € 12-30/t, now € 12/t
- Forward clean spark spread £6-9/MWh
- Forward dark green spread $15-25/MWh

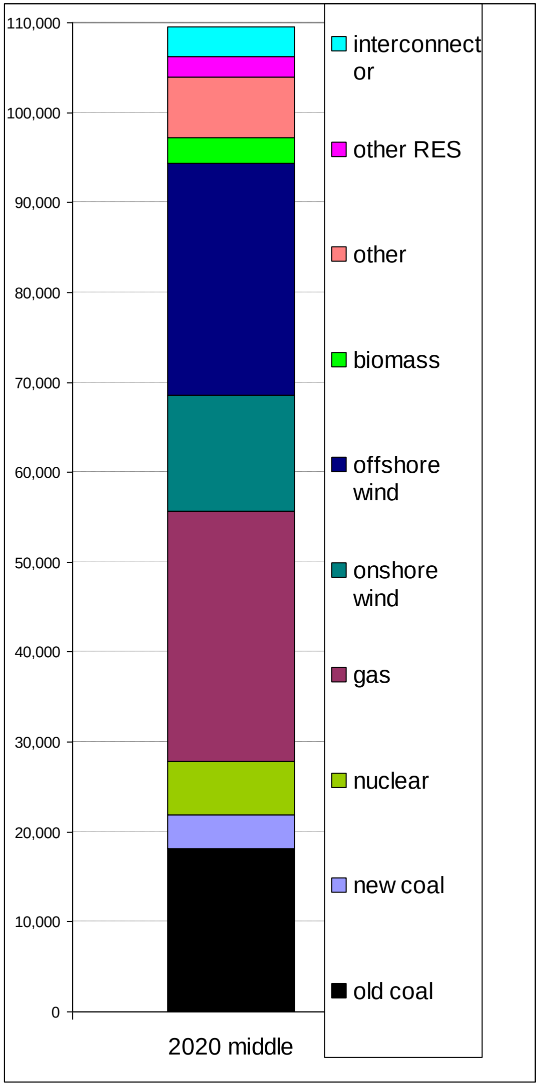
Electricity prices mirror gas prices

Huge generation investment required

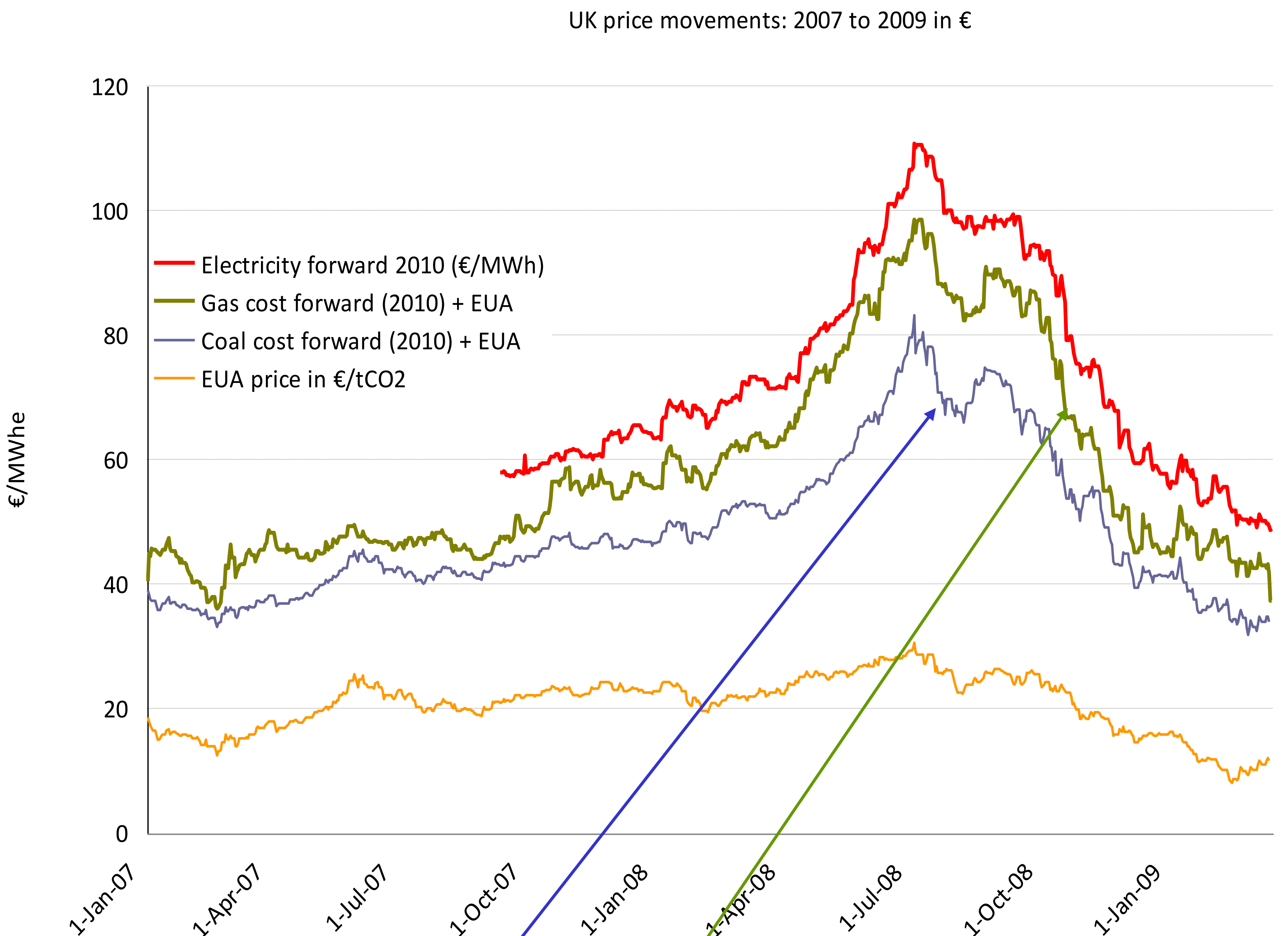
Development of existing GB gen cap



Source: Digest of UK Energy Statistics/DECC

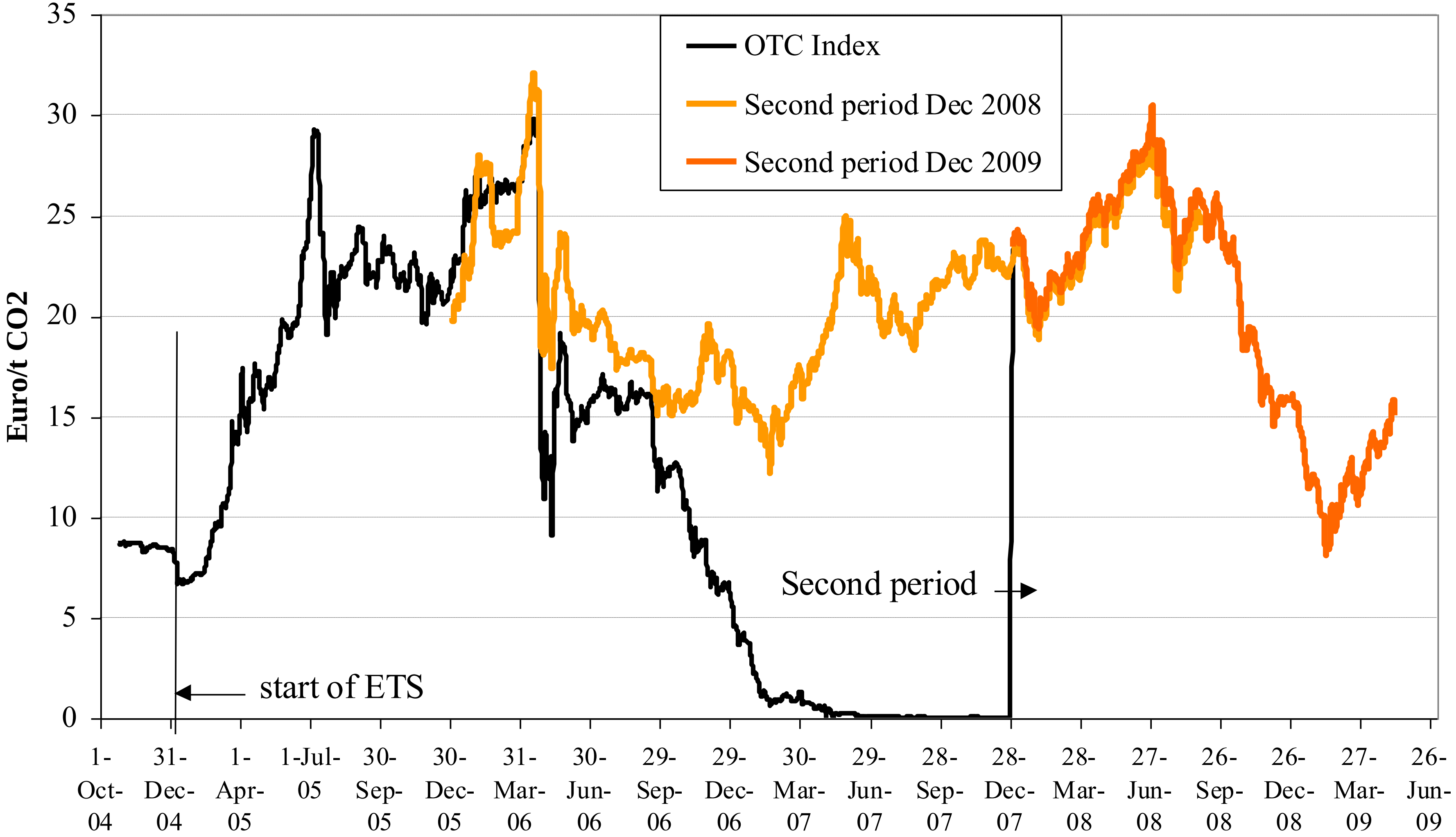


SKM's mid-scenario projection



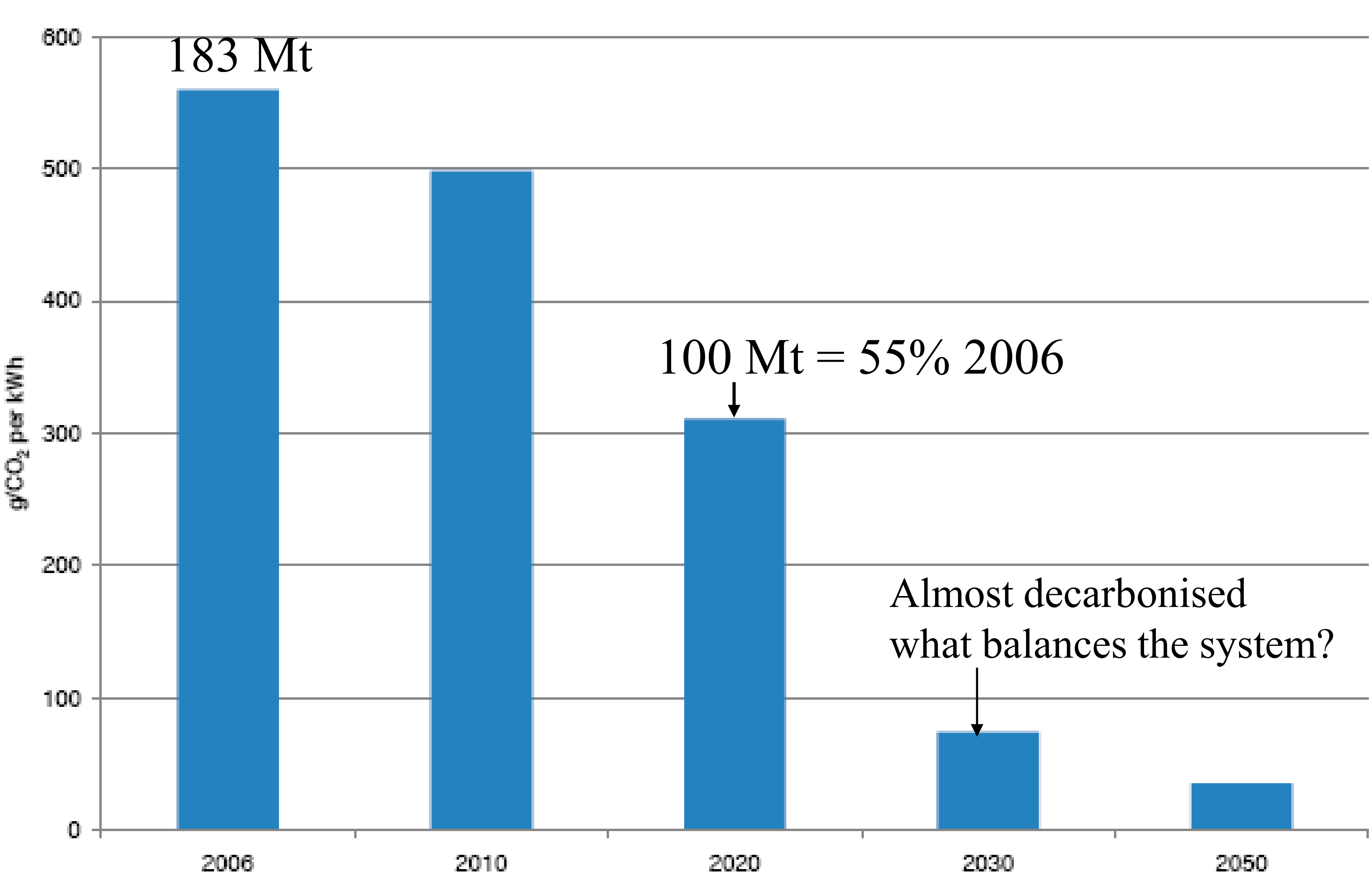
Correlation of coal+EUA on gas+EUA slightly higher at 96%

EUA price 25 October 2004-12 May 2009



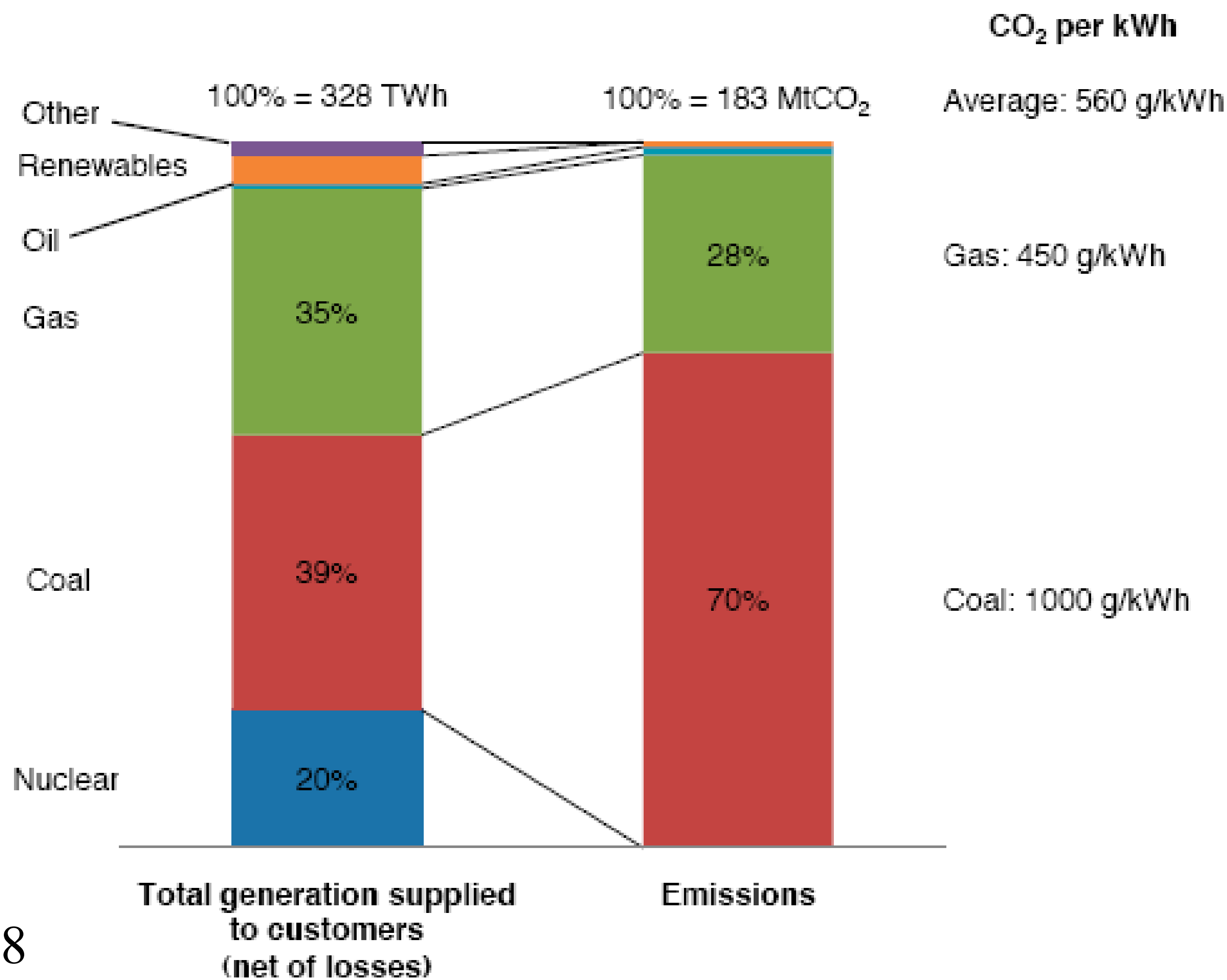
2020 CCC's ESI carbon targets are challenging

Figure 5 CO_2 intensity per kWh of electricity generated, 2006-2050



Source: CCC

Figure 2.2 UK power sector generation and emissions, 2006



CCC 2008

Data for 2006, from the Digest of UK Energy Statistics (2008) and the National Atmospheric Emissions Inventory (2008)

Note: Generation and CO_2 from centralised generation only.

Table 7.6 Lifetime levelised costs of plant added by 2020 (£/MWh)

		2020 Renewable Scenarios		
Technology	Conventional	Lower	Middle	Higher
New coal	56.4	57.4	58.7	61.1
New CCGT	56.5	58.5	59.8	62.8
Nuclear	37.9	37.9	37.9	37.9
Onshore wind*	65.7	60.4	60.4	61.6
Offshore wind*	87.8	86.4	83.4	81.7
Biomass*	95.6	95.7	96.5	101.7

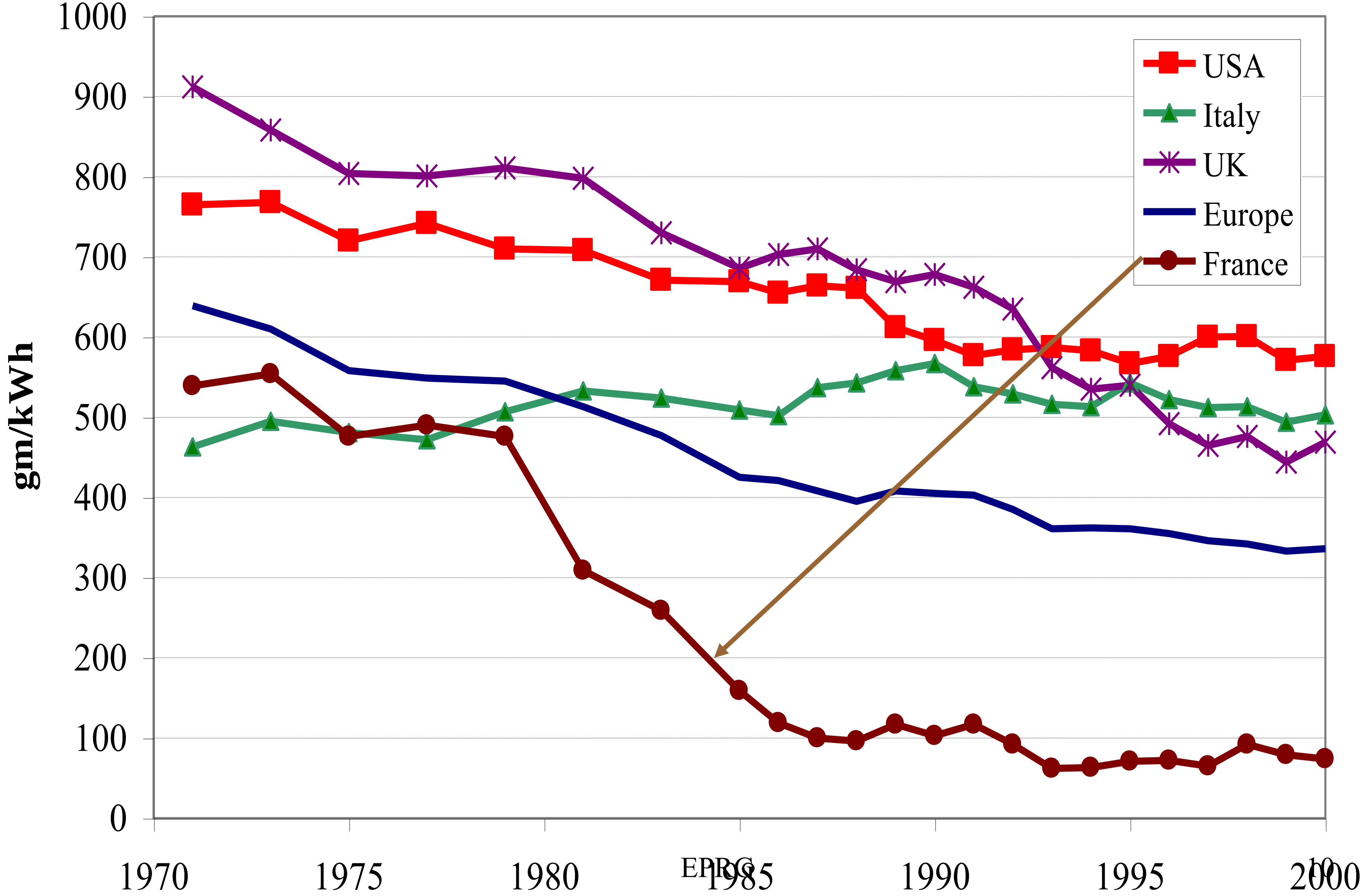
*Before any ROC subsidy, currently around £40-45/MWh

Table 7.2 2020 Price assumptions

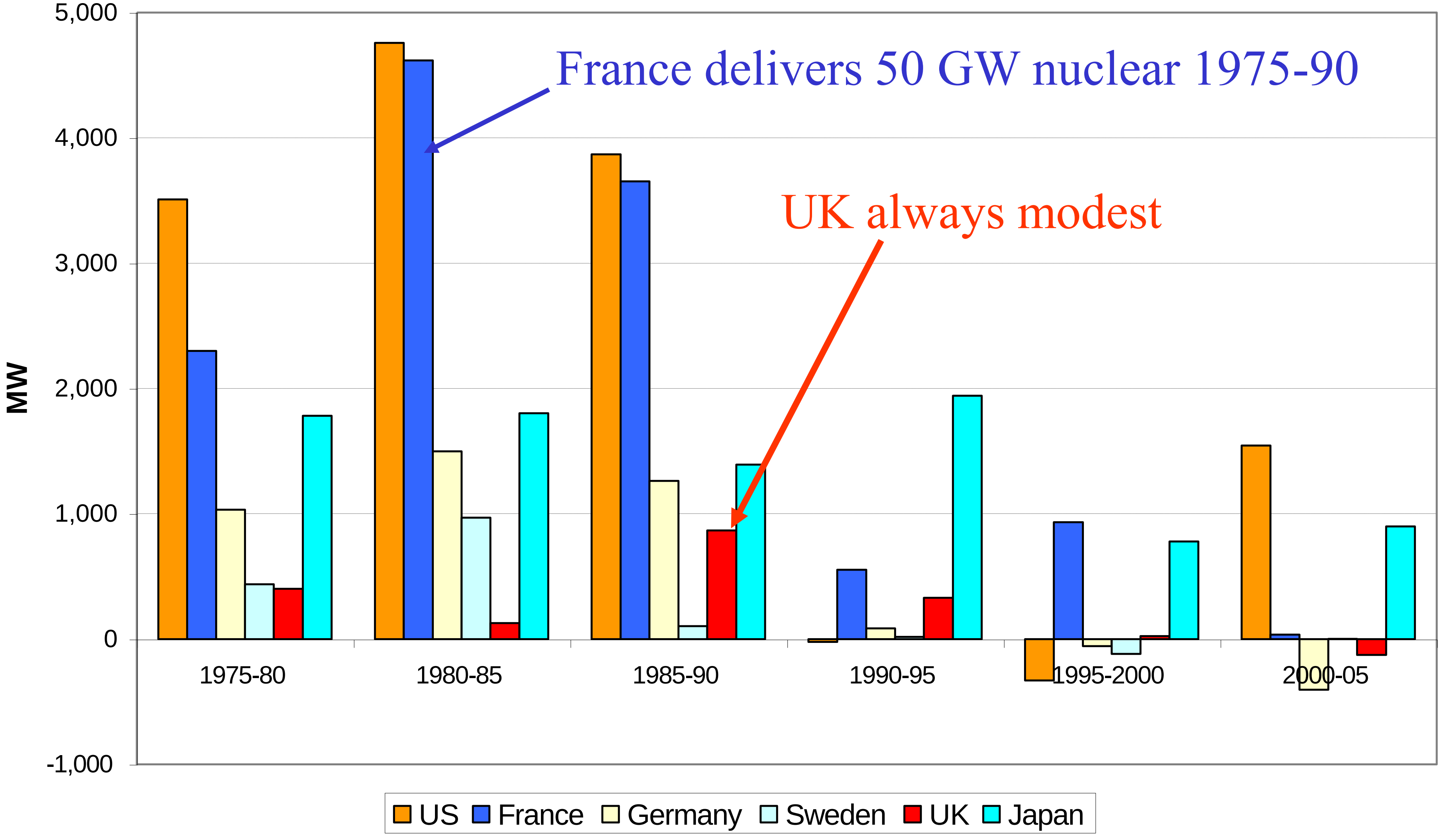
Type	Price
Gas (p/therm)	55
Coal ($/te)	110
Oil ($/barrel)	85
Biomass fuel (£/GJ)	3.6
Carbon permit (€/te CO2)	30

Source: SKM
BERR URN 08/1021

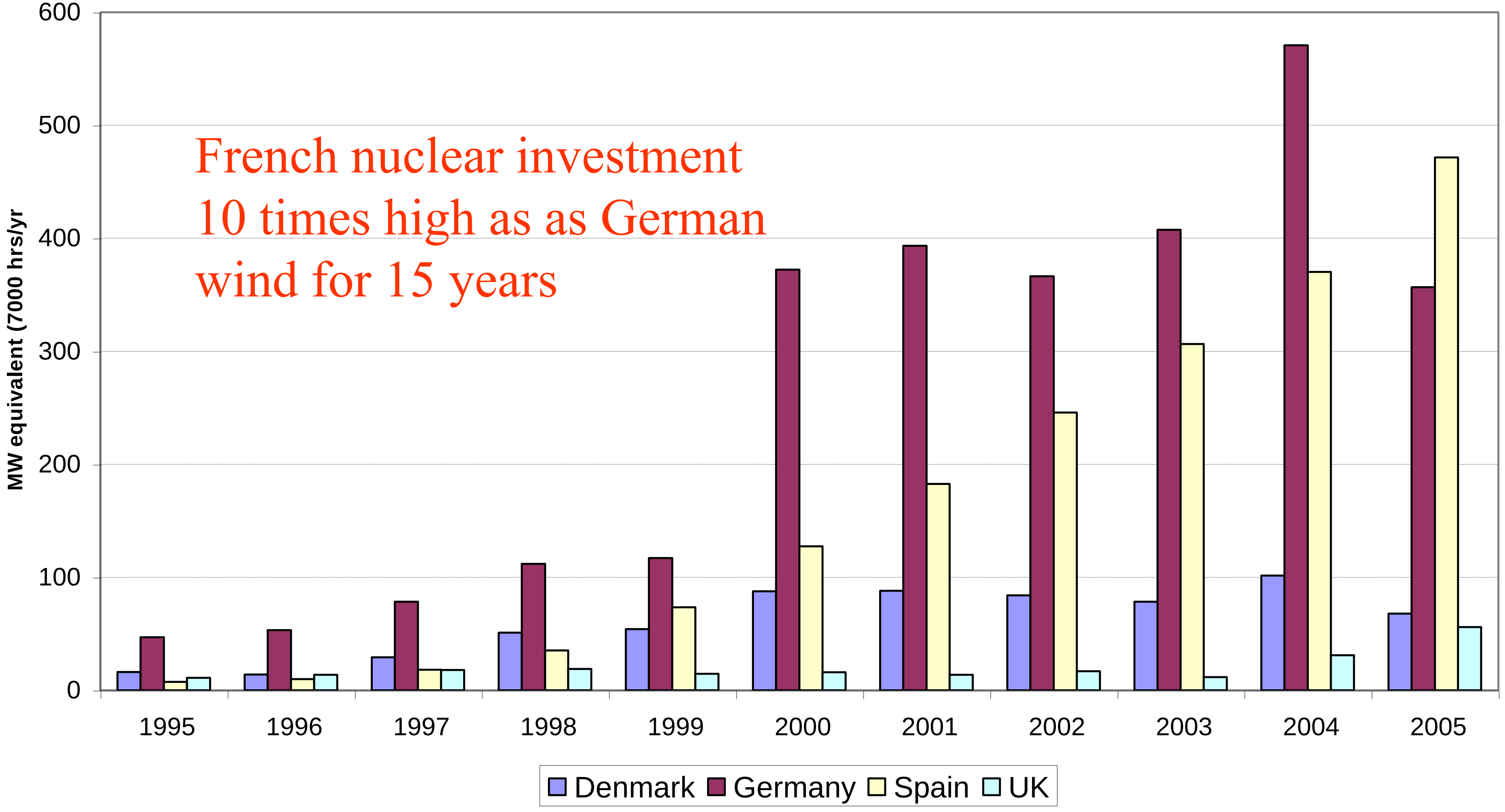
CO2 emissions per kWh 1971-2000



Average annual increment to nuclear capacity



Equivalent increment in effective wind capacity previous five years



UK's 2020 renewables target

= 40% renewable **ELECTRICITY** (SKM mid scenario)

= 150 TWh; wind = 38GW; total 110 GW

- 56 GW conventional @ 31% fossil fuel load factor
- investment cost of renewables = £60 bn + £13 bn grid
- of non-renewables = £12 b, (£coal=3.9b; nuclear = £3.9b)

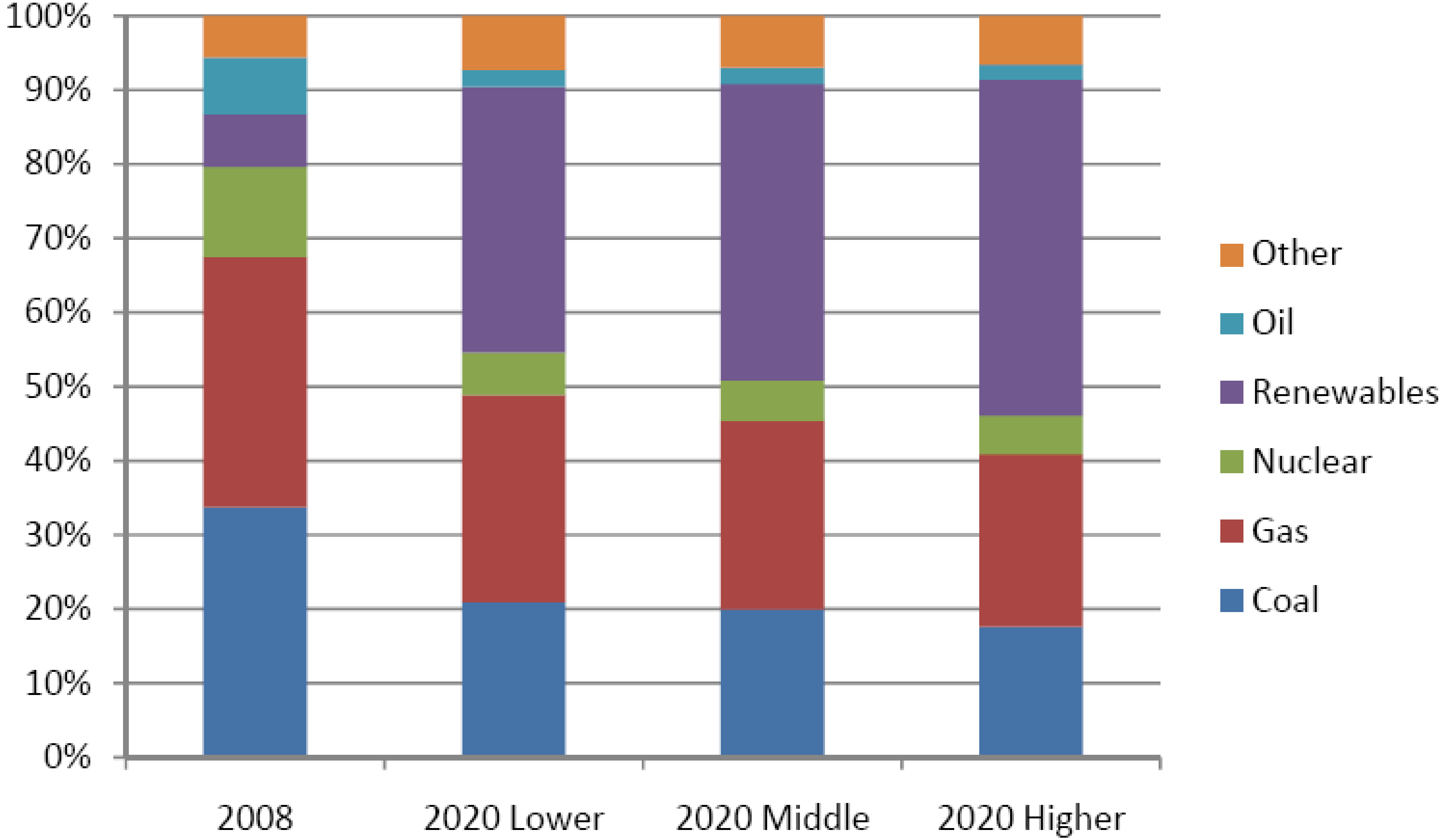
= £80/t CO_2 c.f. £10/t current EUA

- 38 GW> demand for many hours

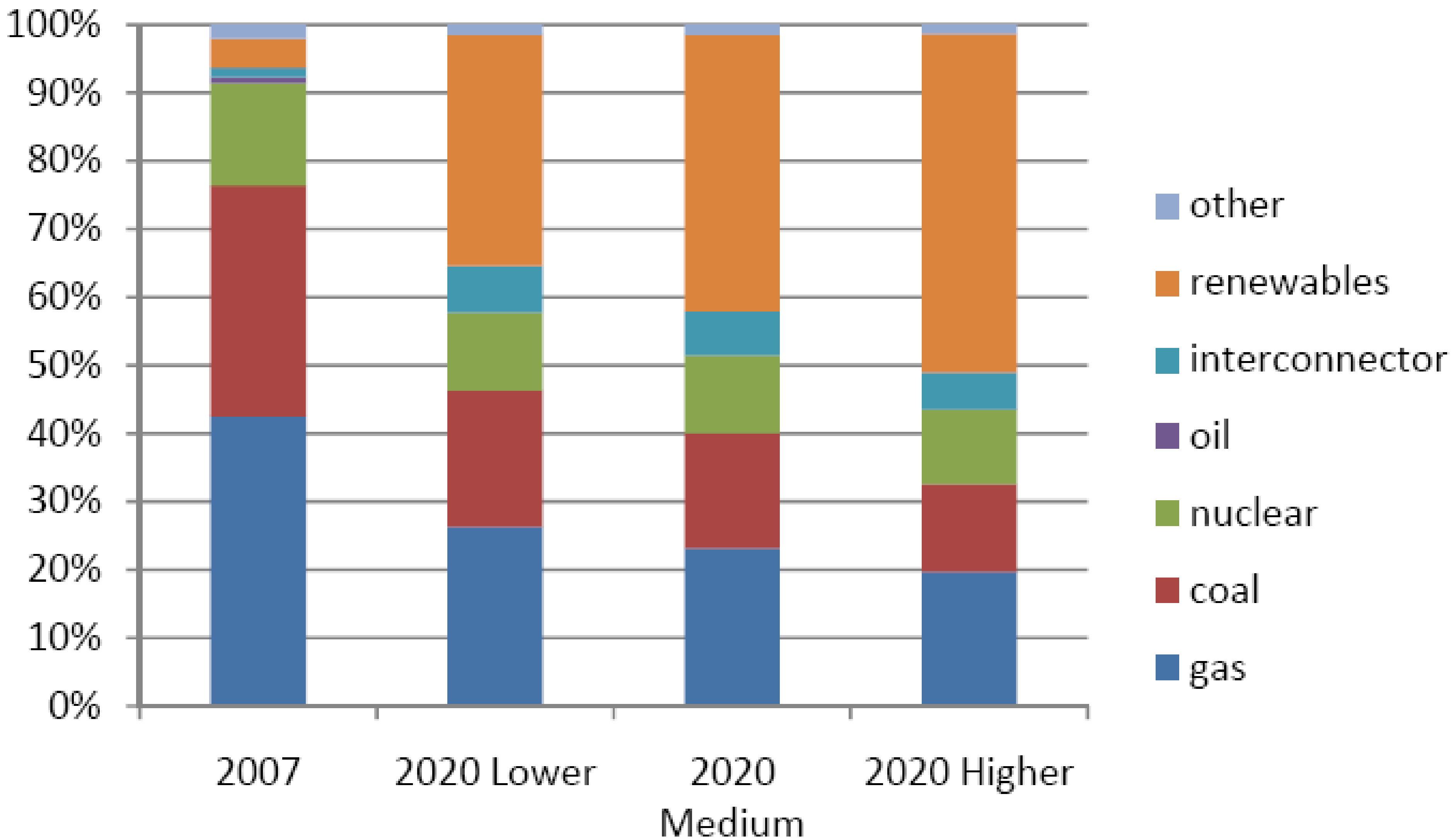
  => volatile supplies, prices, congestion, ….

- Offshore wind dependent on electricity price
  - now looks unfavourable even with banded ROCs
  - FIT cheaper than HMG's banded ROCs (Redpoint)

SKM's projected capacity mix



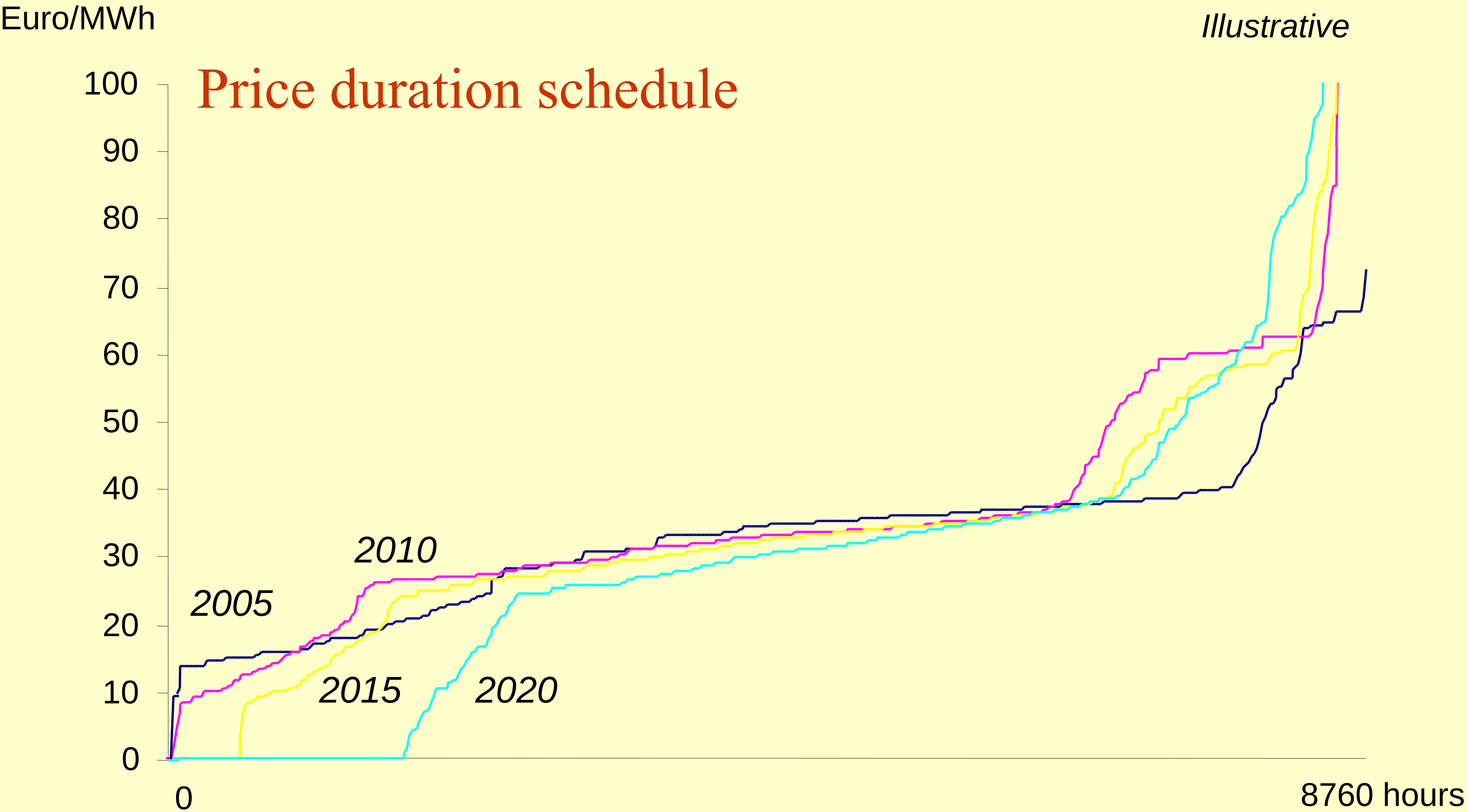
SKM's projected output mix



Implications of substantial wind

- Much greater price volatility
  - mitigated by nodal pricing in import zones
  - requires CfDs and nodal reference spot price
- Reserves (much larger) require remuneration
  - VOLL*LOLP capacity payment?
  - or contracted ahead by SO?
  - Or will spot price volatility induce contracts that cover availability costs?

Simulation – more volatility, harms baseload (nuclear)



Is nuclear viable in liberalised markets?

- Credit supply drying up
  - low risk free rate (indexed bonds)
  - but high cost of capital to most companies
- Low debt-equity needed for construction
- electricity price-cost margin very volatile
  - issue electricity indexed bonds?
  - or require long-term carbon price guarantee?

Is any electricity investment viable without an off-take contract?

Costs of renewables (Ofgem)

- 150 TWh renewables by 2020?
- 2006/7 14.6 TWh = £10/year/HH (household) HH 29% total =£250 m; total £870m
- BERR predicts £32-53/HH/yr
  - HH = £0.8-1.32 b/yr; total = £2.8-4.6b/yr
- SKM's estimate = £60-90/HH =>£5.2-7.8b/yr

Even the low estimate is a 6-fold increase

Towards a Single Buyer?

- The cost of off-shore is huge
  - unsustainable in current conditions?
  - Precipitate move to long-term contracting?
  - Spot market too risky to support investment?
  - Balancing market works overtime with wind
- Any investment without a long-term contract?
  - But then need a Single Buyer?
  - With short-fall in spot market revenue via capacity payment charged through grid?

How long before a viable market design?

Current transmission access

- Connect for firm access
  - delay until reinforcements in place

=> excessive T capacity for wind
  - excessive delays in connecting wind

- TSO uses contracts and Balancing Mechanism to manage congestion
  - weak incentives on G to manage output
  - costly to deal with Scottish congestion

Balancing - problems and requirements

- efficient dispatch: schedule ahead of time
  - to allow for warm-up, ramping, etc
- wind forecasts increasingly accurate at -4hrs
- day-ahead market bad for wind contracting
- etc?

Summary of problems

- Losses not reflected in dispatch
- T access is firm - all or nothing
- Constraints only reflected through BM
  - may be OK if BM efficient and competitive, but is it? thin market? Dual pricing?
- Intertemporal dependencies may not be efficiently handled
  - would short run wind output forecasts allow more efficient scheduling of fossil plant?

The argument for change

- A flawed system can be improved

=> potentially everyone can be made better off

- The challenge:
  - identify the efficient long-run solution
  - that can co-exist with an evolving regime for incumbents
  - apply new regime to all new generation
  - which compensates incumbents for any change
  - while encouraging them to migrate

Efficient congestion management

- Nodal pricing or LMP for optimal spatial dispatch
- All energy bids go to central operator
- Determines nodal clearing prices
  - reflect marginal losses with no transmission constraints
  - Otherwise nodal price = MC of export (or MB of import)
- Bilateral energy contracts
  - Can submit firm bids => pay congestion rents
  - Can submit price responsive bids => profit over
- Financial transmission contracts hedge T price risk

Spatial and temporal optimisation

=> nodal pricing + central dispatch

- Nodal price reflects congestion & marginal losses
  - lower prices in export-constrained region
  - efficient investment location, guides grid expansion
- Central dispatch for efficient scheduling, balancing
- Market power monitoring – benchmark possible
- PJM demonstrates that it can work
  - Repeated in NY, New England, California (planned)

Objections to nodal pricing

- Disadvantages Scottish generators
  - but would benefit voting Scots consumers!

=> Large revenue shifts for small gains

- All earlier attempts thwarted by courts

=> need to compensate losers

Need to make change ***before*** large investments made (wind + transmission)

Other options?

- Can the present system be made to work?
  - Allow G entry - connect and manage?
  - but what about efficient spatial and temporal dispatch?

=> Trading of firm access rights? (OK in theory?)
  - Liquidity – does not even exist at UK level
  - Loop flows –require complex reconfiguration
  - cannot address efficient intertemporal dispatch/balancing
- Liquid competitive markets => efficiency (if externalities reflected in prices)

Hard to imagine trading can achieve all this

Transition for existing plant

- Existing G receives long-term transmission contracts but pays grid TEC charges
- for output above TEC, sell at LMP

$\Rightarrow$ G significantly better off than at present

$\Rightarrow$ No T rights left for intermittent generation

Challenge: devise contracts without excess rents and facilitate wind entry

Conclusions-1

- Renewables target requires *and currently lacks*
  - efficient transmission access regime
  - efficient market design for dispatch and balancing

=> ideal: nodal pricing + pool/SO control

- transition arrangements
  - for new/old Generation

=> careful transition contracts to avoid excess rents

Conclusions-2

- Renewables and other targets undermine liberalised market

=> threatens ***all*** generation investment

- Current support for renewables risky and costly

=> required shift to long-term contracting marks end of liberalised market?

Nuclear power needs an attractive offering to compete politically with renewables:

attractive real return with sensible C price

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Spare slides if needed

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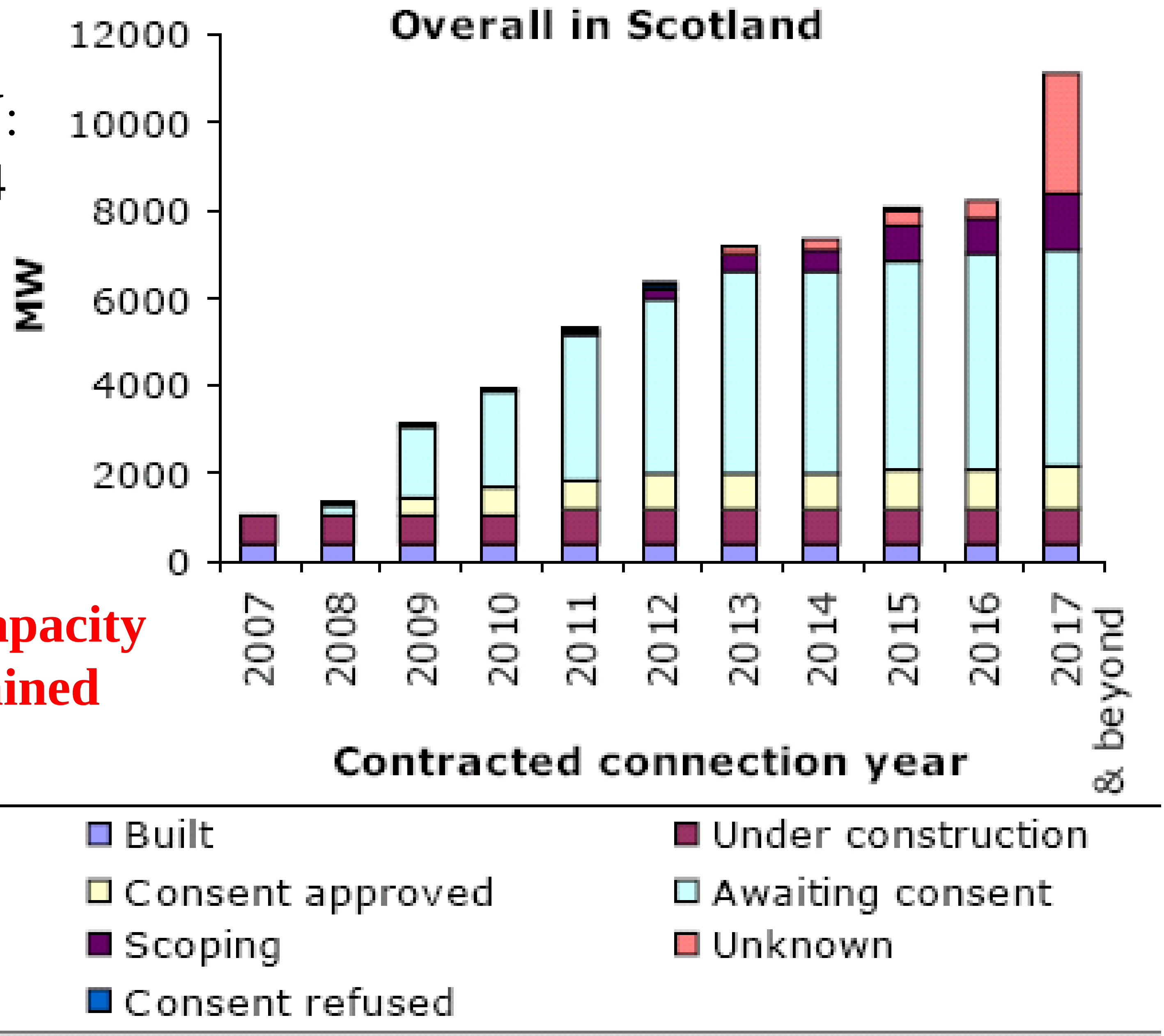
Existing MW:
Thermal = 1,524
Hydro = 1,100
Wind = 650
pump
storage = 300
demand = 1650



2 GW export capacity already constrained

Effects of efficient nodal pricing

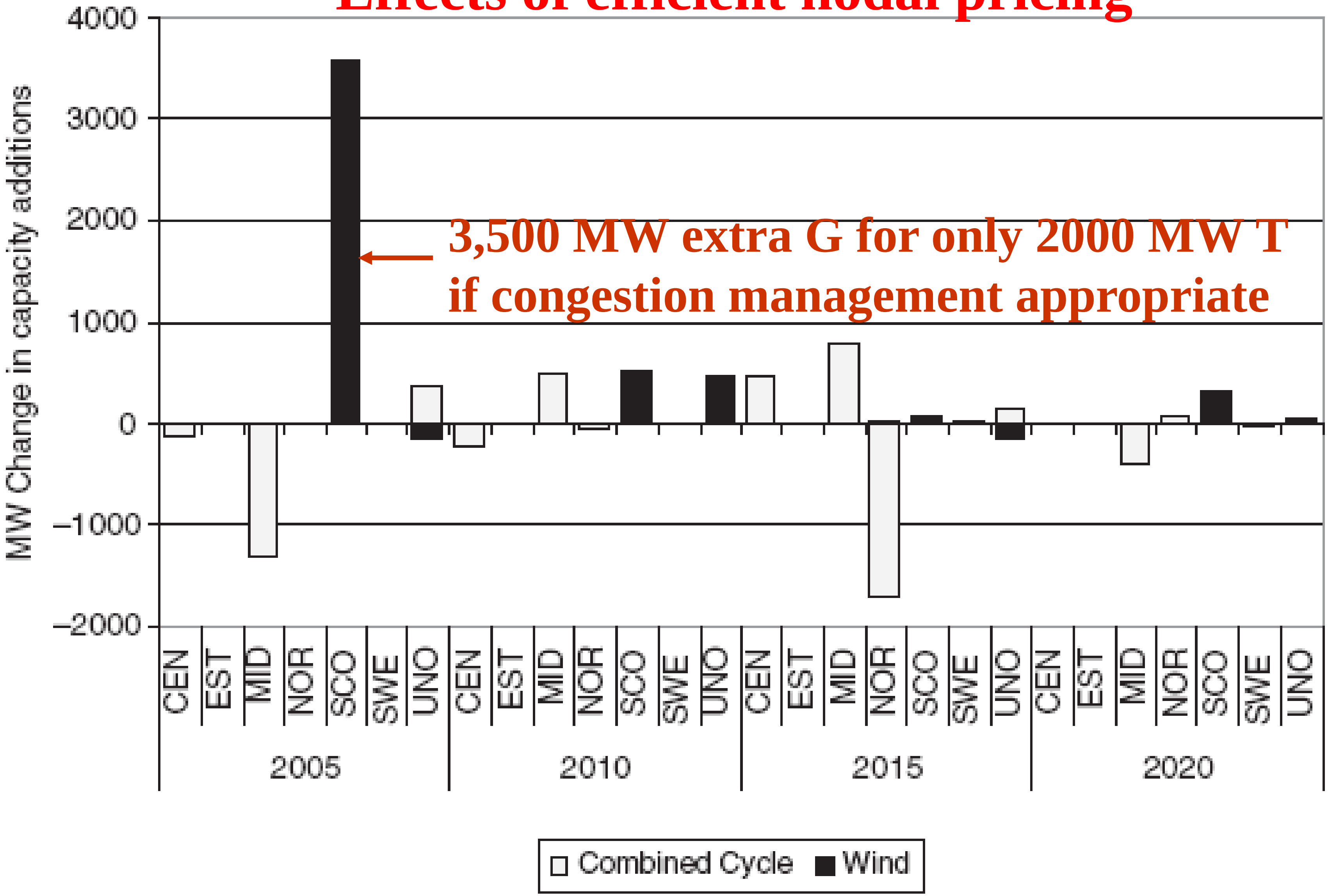


Figure 6.6. Change in investment relative to Scenario M2 with 2GW transmission expansion

Efficient balancing market

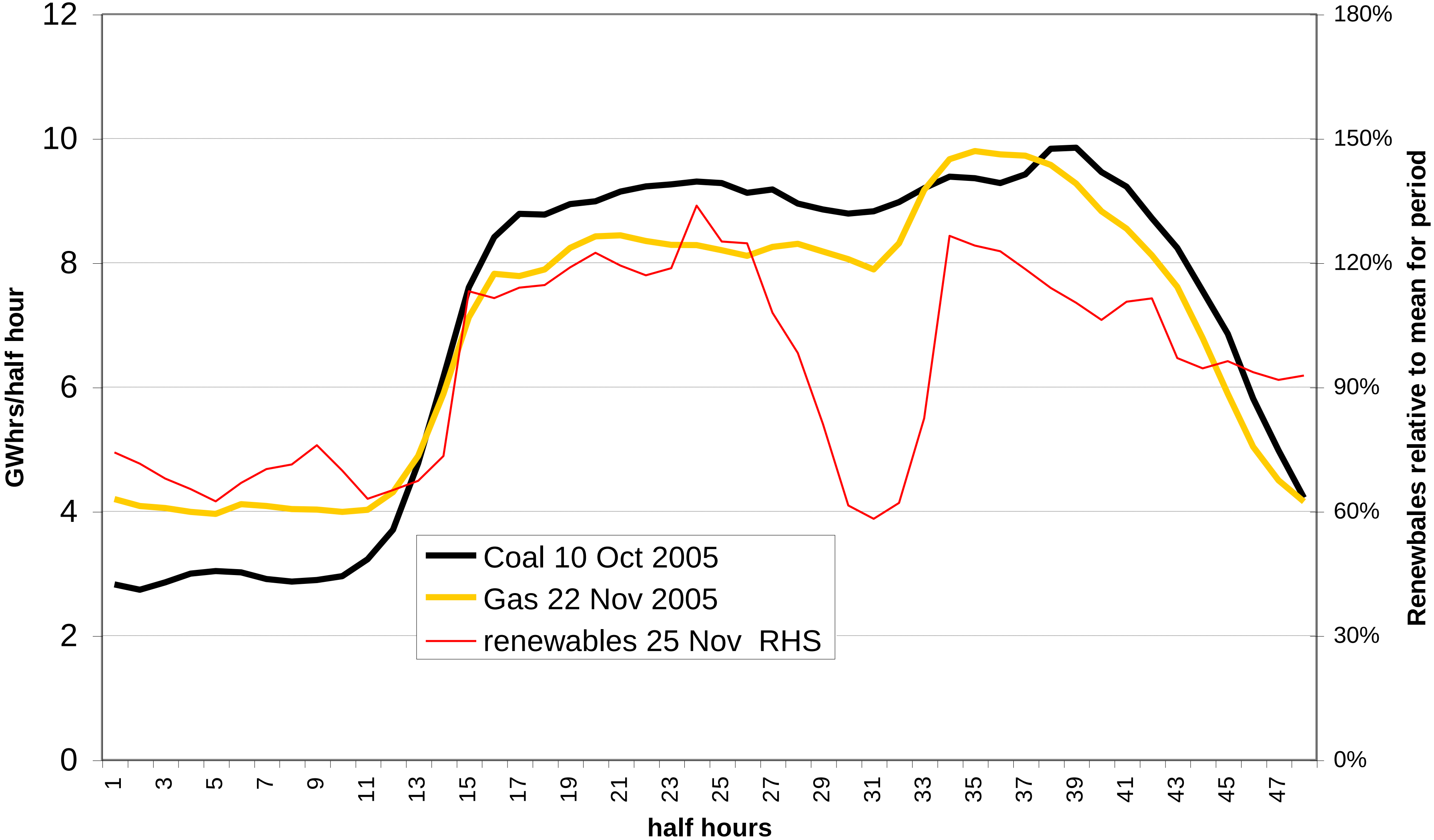
- Use right combination of plants to
  - provide spinning reserve
  - provide flexibility to vary output over periods of mins - 4 hours (i.e. are warm, and given ramping constraints)
  - meet next demand peak and demand low
  - handle varying transmission constraints

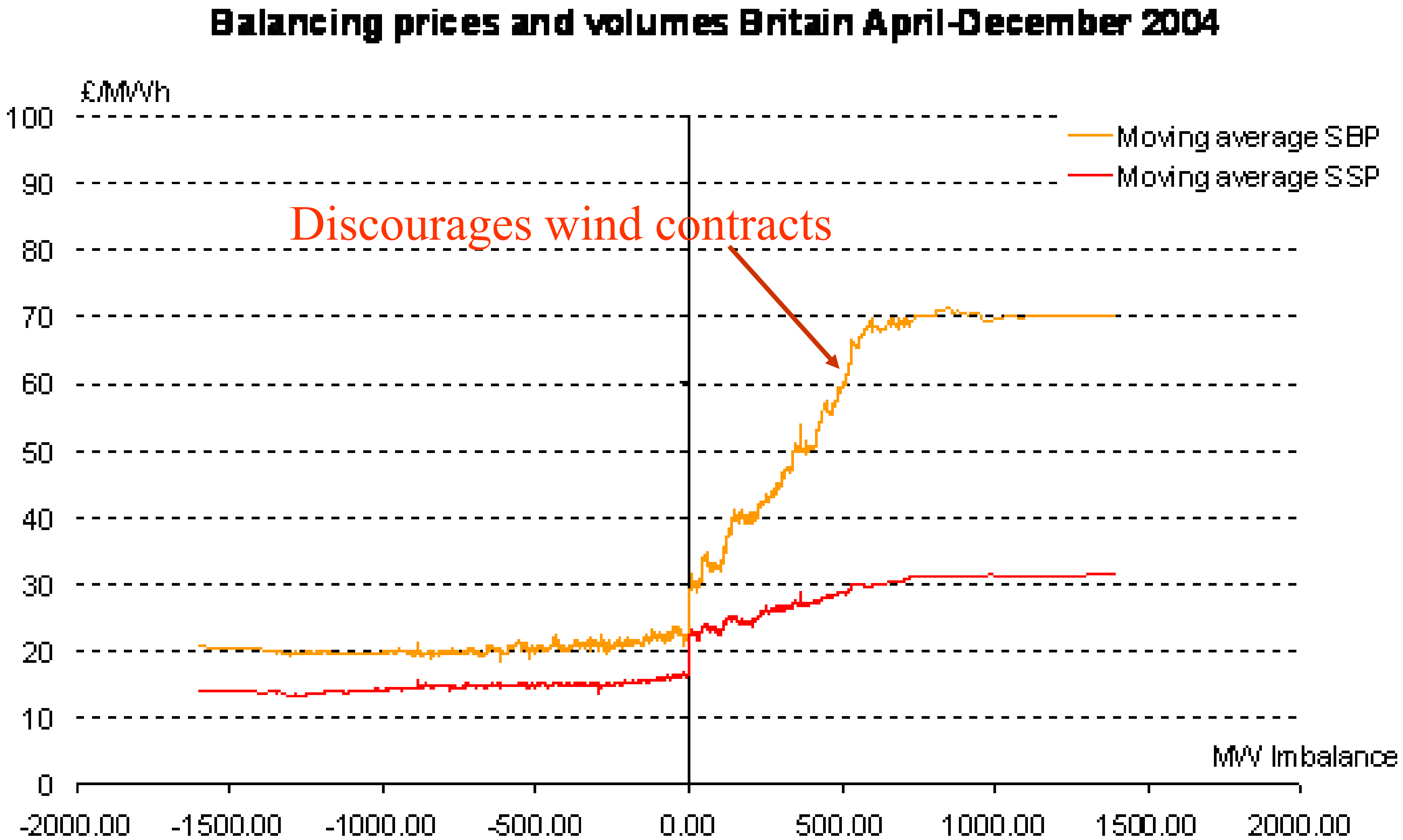
=> inter-temporal optimisation, updated with new wind/demand forecasts

- Market participants submit multi-part bids
  - Start up cost/time, Ramping rates, etc
  - Marginal generation cost
  - Part load constraint, etc

=> POOL type approach

Ability to vary thermal output





Balancing prices and volumes Britain April-December 2004
£/MWh
100
90
80
70
60
50
40
30
20
10
0
Moving average SBP
Moving average SSP
Discourages wind contracts
MW Imbalance
-2000.00
-1500.00
-1000.00
-500.00
0.00
500.00
1000.00
1500.00
2000.00

Politics and constraints

- Aim: Security, Sustainability, Affordability
- choose any two of three?
  - Or minimise cost of achieving efficient level of security while meeting CO_2 and renewables objectives
- Currently costs all levied on consumers
  - and excessive because of ROCs etc

This could create more uncertainty

Fuel poverty

Annual average domestic standard electricity bill