Transition to a low carbon electricity market and needed reforms

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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

SKM’s mid-scenario projection

Source: Digest of UK Energy Statistics/DECC
Correlation of coal+EUA on gas+EUA slightly higher at 96%

OTC Index
Second period Dec 2008
Second period Dec 2009

start of ETS
Second period

Euro/t CO2

1- Oct- 04
31- Dec- 04
1- Apr- 05
30- Sep- 05
30- Dec- 05
31- Mar- 06
30- Jun- 06
29- Sep- 06
30- Dec- 06
29- Mar- 07
30- Jun- 07
28- Sep- 07
28- Dec- 07
28- Mar- 08
27- Jun- 08
26- Sep- 08
26- Dec- 08
27- Mar- 09
26- Jun- 09
2020 CCC’s ESI carbon targets are challenging

Figure 5  CO$_2$ intensity per kWh of electricity generated, 2006-2050

- 183 Mt
- 100 Mt = 55% 2006
- Almost decarbonised
- What balances the system?
Figure 2.2  UK power sector generation and emissions, 2006


Note: Generation and CO₂ from centralised generation only.
Table 7.6 Lifetime levelised costs of plant added by 2020 (£/MWh)

<table>
<thead>
<tr>
<th>Technology</th>
<th>Conventional</th>
<th>2020 Renewable Scenarios</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>Lower</td>
</tr>
<tr>
<td>New coal</td>
<td>56.4</td>
<td>57.4</td>
</tr>
<tr>
<td>New CCGT</td>
<td>56.5</td>
<td>58.5</td>
</tr>
<tr>
<td>Nuclear</td>
<td>37.9</td>
<td>37.9</td>
</tr>
<tr>
<td>Onshore wind*</td>
<td>65.7</td>
<td>60.4</td>
</tr>
<tr>
<td>Offshore wind*</td>
<td>87.8</td>
<td>86.4</td>
</tr>
<tr>
<td>Biomass*</td>
<td>95.6</td>
<td>95.7</td>
</tr>
</tbody>
</table>

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

Table 7.2 2020 Price assumptions

<table>
<thead>
<tr>
<th>Type</th>
<th>Price</th>
</tr>
</thead>
<tbody>
<tr>
<td>Gas (p/therm)</td>
<td>55</td>
</tr>
<tr>
<td>Coal ($/te)</td>
<td>110</td>
</tr>
<tr>
<td>Oil ($/barrel)</td>
<td>85</td>
</tr>
<tr>
<td>Biomass fuel (£/GJ)</td>
<td>3.6</td>
</tr>
<tr>
<td>Carbon permit (€/te CO2)</td>
<td>30</td>
</tr>
</tbody>
</table>

Source: SKM
BERR URN 08/1021
CO2 emissions per kWh 1971-2000

USA
Italy
UK
Europe
France
Average annual increment to nuclear capacity

-1,000
0
1,000
2,000
3,000
4,000
5,000


MW

US France Germany Sweden UK Japan

France delivers 50 GW nuclear 1975-90

UK always modest
French nuclear investment 10 times high as as German wind for 15 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 CO₂ 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

- **2007**
  - Gas: 40%
  - Coal: 30%
  - Nuclear: 20%
  - Others: 10%

- **2020 Lower**
  - Gas: 20%
  - Coal: 60%
  - Nuclear: 20%

- **2020 Medium**
  - Gas: 30%
  - Coal: 50%
  - Nuclear: 20%

- **2020 Higher**
  - Gas: 40%
  - Coal: 30%
  - Nuclear: 20%
  - Others: 10%
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 £870 m
- BERR predicts £32-53/HH/yr
  - HH = £0.8-1.32 b/yr; total = £2.8-4.6 b/yr
- SKM’s estimate = £60-90/HH => £5.2-7.8 b/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
  ⇒ G significantly better off than at present
  ⇒ 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
Spare slides if needed

http://www.electricitypolicy.org.uk
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

3,500 MW extra G for only 2000 MW T if congestion management appropriate

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

Coal 10 Oct 2005
Gas 22 Nov 2005
renewables 25 Nov
Discourages wind contracts
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

- 4 million taken out of fuel poverty by £100 fall
- 500,000 more for a £20 rise

- pre-payment
- standard credit
- fuel poor England
- fuel poor UK

Number of households fuel poor millions

£ per year