Market design for large shares of renewables: time and space

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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
The challenge of renewables

• 20% EU renewables target by 2020 agreed
  = 15% renewable ENERGY for UK
  = 30-40% renewable ELECTRICITY
• likely to be large shares of wind
  – Much in Scotland: queue of 11 GW, 9GW Wales
• At 25% capacity factor, 25% wind
  = 100% peak demand
=> volatile supplies, prices, congestion, ....
Electricity generated gross

GWh

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renewables
hydro
other CCGT
majors' CCGT
other's thermal
majors' thermal
nuclear
**Existing MW:**
- Thermal = 1,524
- Hydro = 1,100
- Wind = 650
- Pump storage = 300
- Demand = 1650

2 GW export capacity already constrained
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
Re-dispatch to resolve constraints in England and Wales

Costs rise rapidly with constrained links to Scotland
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?
Ability to vary thermal output

Coal 10 Oct 2005
Gas 22 Nov 2005
renewables 25 Nov RHS
Discourages wind contracts
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
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
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
Contract design for Scottish FTRs

Current system

- Wind output varies over time
- Power price (GB)
- MC coal
- time

Proposed system

- Wind output (Scotland)
- Power price (London)
- Export constraints on Scot thermal
- time

- FTR option for incumbent
- FTR option not given to incumbents
- Net profit energy

Caps FTR revenue to incumbents

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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, adequate reward for CCGT

Price duration schedule
Price duration curves under the Pool and Balancing Mechanism
Implications of volatility

- carbon price - set in expectation of renewables?
- Coal and OCGT for peaking/balancing?
- Encourages interconnectors (esp to Norway)
- Base-load plant margins fall to CCGT level
  => discourages high capital cost plant (nuclear, CCS)
  => increased need for contracting (good)
  => further stimulus to integration? (not so good)
Conclusions

• 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
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