

Charging Issues Standing Group Short-term access pricing

8 June 2009

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Agenda

CAP164: Connect & manage WGAA

- ◆ Summary of CUSC Conclusions Report

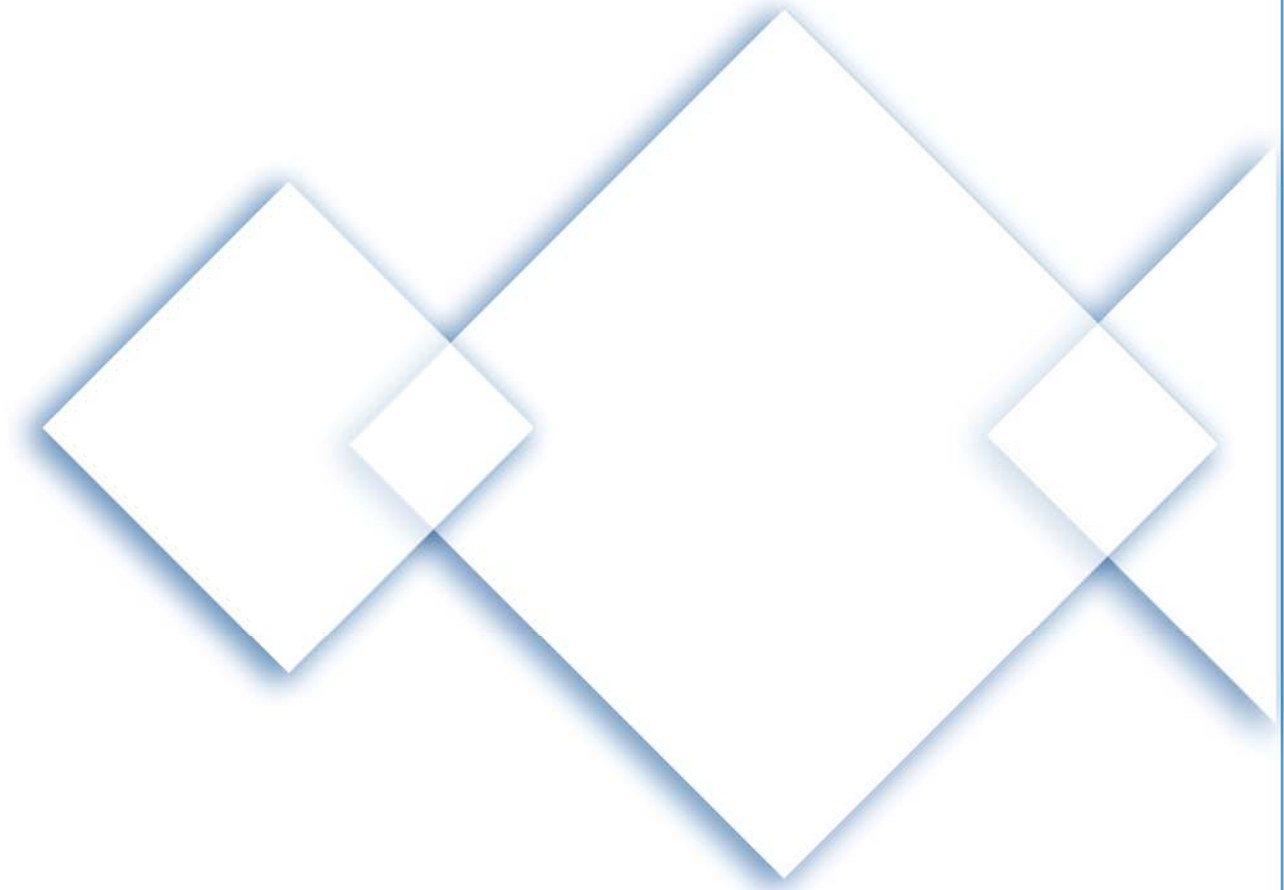
Pricing for connect & manage alternative

- ◆ Summary of analysis completed by National Grid
- ◆ Summary of TCMF discussion

Discussion

- ◆ Views?
- ◆ What further analysis is required?

Timescales



CAP164: Connect & manage

Summary of CUSC Conclusions Report

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CAP164 Connect and manage

◆ Original

- Parties gain access within 4 years, subject to local works
- Incremental costs are smeared across all users
 - Locational BSUoS would target the additional cost to contracted parties behind the non compliant boundary.
- Force majeure excludes planning consents for wider works
- UC covered by CAP165

◆ Alternative

- Access available from completion of local works
- Incremental costs are targeted to the new connectee
- Period of incremental cost exposure related to infrastructure works
 - Fixed date
 - Fixed tariff
- UC 4years stepped at 25% pre commissioning & 8 years post commissioning.

Timescales CAP164 Alternative

CAP164 Alternative

Payments
 Local TNUoS
 Residual TNUoS
 Ex ante constraint
 forecast
 BSUoS

Payments
 Local TNUoS
 Residual TNUoS
 Wider TNUoS
 BSUoS

Apply

Local works ready
 – Local Connection
 date

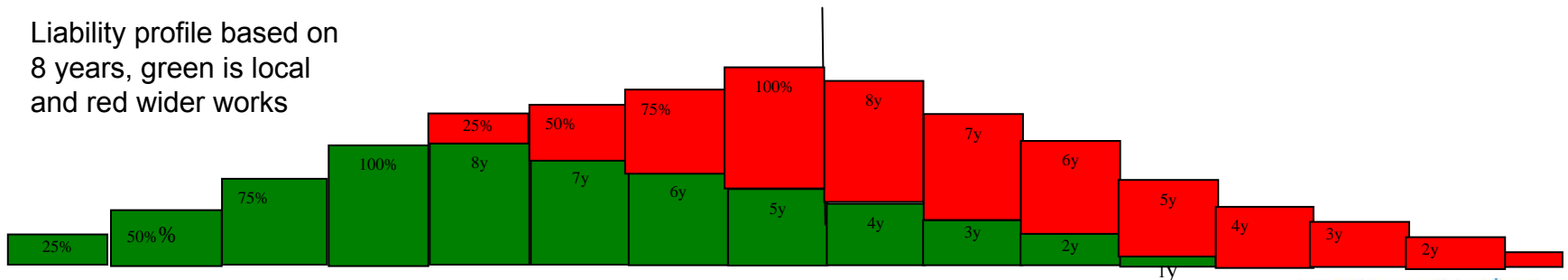
Wider works ready – date fixed
 (TEC Guaranteed Date, and in this
 example also TEC Effective Date)

Liability
 based on local works
 from connection date -4y

Liability
 decreasing on local
 liability based on wider
 from firm date -4y

Liability still
 decreasing on local
 and also decreasing
 on wider

Liability profile based on
 8 years, green is local
 and red wider works



CAP164 Alternative charging

- ◆ ‘a fixed cost reflective price which could either be a flat £/kWh figure or profiles on a seasonal / weekly / daily basis where this could provide improved cost reflectivity’
- ◆ Batch process applications
- ◆ Exante forecast of constraints based on applications
- ◆ Offers will include the calculated tariffs
- ◆ Tariffs recalculated on accepted volumes

Issues to be thought about

- ◆ Targeted costs
 - full bid offer spread
 - Actual or administered
 - Sharing with existing same zone, all gen and demand
- ◆ Average (CR) or Marginal
 - Interaction with ST and LT
- ◆ £/MWh under CUSC proposals, £/kW
- ◆ Profiling / granularity
- ◆ Interaction with SoW
 - Embedded users contributing to cost not currently charged



Pricing for connect & manage alternative

Summary of analysis completed by National Grid and discussion at TCMF

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1. Status quo

2. Connect & manage original

- ◆ All new Users get wider access rights in 4 years
- ◆ Increase in operational costs socialised

3. Connect & manage alternative

- ◆ All new Users submit requests for network access and NG provide associated offers
 - Access is granted when local works are complete
 - Between completion of local and wider works, Users pay price based on NG forecast of additional constraint costs caused
 - Ex ante average cost
 - From forecast wider works completion date, Users pay TNUoS
- ◆ Users either accept or reject offer
 - Price for those that accept is recalculated (if some Users have not accepted)
- ◆ Additional notice period for TEC reduction (CAP165 alternative) assumed

4. Interim connect & manage with locational BSUoS

- ◆ All Users get wider access on completion of “local” works
- ◆ If wider system boundaries become non-compliant with SQSS, operational costs due to non-compliance targeted at generators on the exporting side of the non-compliant boundary
 - Ex post average cost

National Grid analysis: Pricing scenarios

The following scenarios have been considered:

- ◆ Scenario 1: Assume an additional £40m pa of constraint costs caused by the connection of an additional 450MW (1.2TWh) of wind generation in Northern Scotland
 - Based on constraint forecast work associated with consideration of interim connect & manage
- ◆ Scenario 2: Assume an additional £240m pa of constraint costs caused by the connection of an additional 4.62TWh of wind generation in Scotland
 - Based on Brattle analysis for CAP148 Impact Assessment
 - 4 year base case between 2013 and 2018

National Grid analysis: Results for scenario 2

	£/MWh for E&W Thermal Generation	£/MW/h for Scottish Thermal	£/MW/h for Renewables in E&W	£/MW/h for Renewables in Scotland	Cost to Suppliers per annum
Today	S. Nuclear = 1.82 Humber Gas = 2.52 South Coal = 1.10	Nuclear = 3.61 Gas = 5.49 Coal = 6.03	Estuary = 1.66	North Scotland = 9.51 South Scotland = 6.57	Total cost = £1542m
Model 1 – socialise	S. Nuclear = 2.19 Humber Gas = 2.90 South Coal = 1.48	Nuclear = 3.98 Gas = 5.87 Coal = 6.40	Estuary = 2.03	North Scotland Exist = 9.89 New = 9.89 South Scotland = 6.95	+£120m
Model 2 – target at new	S. Nuclear = 1.82 Humber Gas = 2.52 South Coal = 1.10	Nuclear = 3.61 Gas = 5.49 Coal = 6.03	Estuary = 1.66	North Scotland Exist = 9.51 New = 54.91 South Scotland = 6.57	+£0m
Model 3 – loc BSUoS	S. Nuclear = 1.62 Humber Gas = 2.33 South Coal = 0.96	Nuclear = 13.76 Gas = 15.37 Coal = 15.7	Estuary = 1.54	North Scotland Exist = 18.79 New = 18.79 South Scotland = 16.32	-£78m

Summary of TCMF discussion

Initial pricing results for connect & manage alternative appear prohibitively expensive

- ◆ Establish working group to investigate options
 - Target at new
 - Target locationally
 - Socialise

- ◆ Suggestions for further consideration
 - Target percentage at new and remainder locationally
 - New user pays “reasonable” constraint costs
 - Based on fuel prices?

Further analysis to breakdown price 1

We have constructed a spreadsheet model to calculate constraints and the associated shadow costs

- ◆ Generators have been grouped into the following categories: wind; nuclear; base gas; base coal; France; other renewables; water; marginal gas; marginal coal; pumped storage; peakers.
- ◆ Demand has been modelled as a number of blocks across the following seasons: winter high (18 blocks); winter low (13 blocks); summer high (13 blocks); summer low (7 blocks).
- ◆ Generation output and system demand have been sampled based on typical distributions across 500 slices
 - binomial for thermal
 - normal for water
 - triangular for wind
 - typical load duration for demand
- ◆ For each of the 500 slices, an optimisation has been performed to calculate the unconstrained generation schedule [minimise fuel cost subject to total generation = total demand]

Further analysis to breakdown price 2

- ◆ The resulting generation schedule has then been superimposed on a 16 node model of the transmission system (based on the DTIM model developed for the SQSS work with intact and typical outage line rating data) and a further optimisation has been performed to calculate constraint costs [minimise balancing costs (sum of bid/offer receipts/costs) subject to line flows < line ratings].
- ◆ The nodal shadow costs from this second optimisation (£/MWh) have been multiplied by the associated generation output (MWh) in order to calculate transmission receipts. We have employed two approaches to balance transmission receipts with balancing costs:
 - **Fixed adder:** In each slice, add a fixed quantity to each nodal shadow cost (move the hub). This ensures that nodal marginal price differentials are maintained;
 - **Scaled:** In each slice, scale the nodal shadow costs. This reduces nodal marginal price differentials and has been used as a proxy for average prices.

Results 2008/09 1

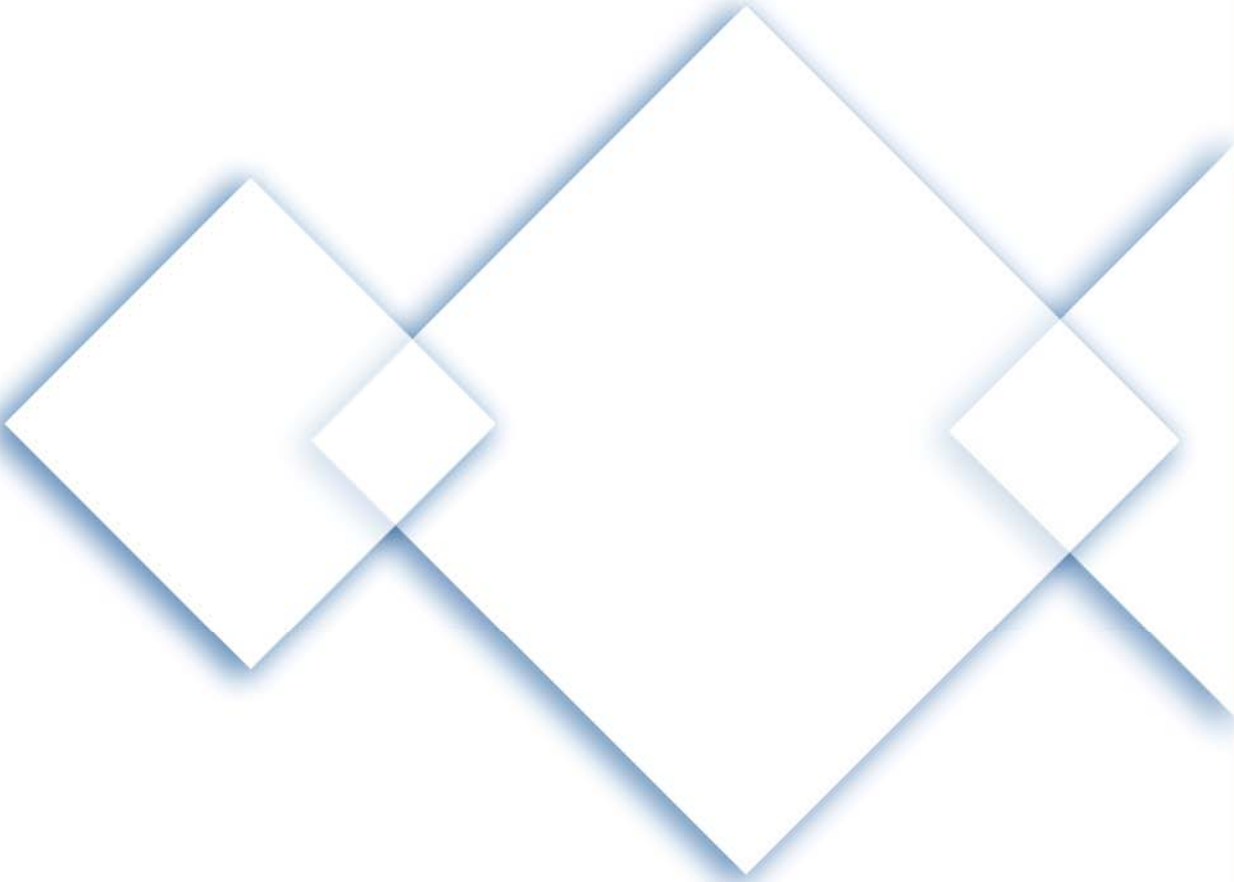
The model has been run for 2008/09 and the constraint costs have been compared with NG forecasts, with particular attention being paid to the Cheviot boundary. The following scenarios have been considered:

- ◆ 2008/09 basecase [total balancing cost = £221m]
- ◆ 2008/09 with additional 450MW of wind generation in Northern Scotland [total balancing cost = £260m]
- ◆ 2008/09 with additional 450MW of wind generation in Northern Scotland and line ratings modified to SQSS compliant levels [total balancing costs = £112.5m]

Results 2008/09 2

Year 2008/09 – All Scenarios (all figures in £/kW)

	Existing N. Scot Wind	New N. Scot Wind	N Scot B/L Gas	Scot B/L Coal	Scot Marg Coal	S. Scot Wind	Scot Nuclear	N. Eng B/L Gas	SE Eng Marg Coal
Status Quo	25.92	25.92	31.21	24.52	16.87	17.93	23.04	17.07	0.33
Status Quo +450	30.18	30.18	29.26	20.00	13.87	16.80	21.96	16.36	-0.21
Loc BSUoS (New Users)	27.43	147.65	31.84	24.67	16.97	17.99	23.10	16.89	0.13
Loc BSUoS (All Users)	31.80	31.80	51.04	42.99	19.27	25.09	40.83	15.77	0.63
Marginal price	116.60	116.60	212.23	203.65	124.62	90.92	194.08	2.47	-2.91
Average price	22.10	22.10	43.70	41.03	24.00	19.45	39.94	16.64	0.10



Additional slides

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Typical bid and offer prices

Generation type	Bid Price (£/MWh)	Offer price (£/MWh)
Wind	-50	10,000
Nuclear	-100	10,000
Base Gas	10	40
Base Coal	15	60
France	20	80
Other renewables	23	90
Water	23	90
Marginal Gas	25	100
Marginal Coal	30	120
Pumped Storage	75	300
Peakers	100	400

Distribution of shadow prices

