

WPD Long Term Methodology work

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Summary of progress

- Work undertaken with the University of Bath from March 2005 to May 2006 to establish core methodology
- Presentations made to ISG on work with University of Bath
- Consultation undertaken in January 2006 to inform users about our work
- Further consultation issued 14th July proposing significant change to our UoS Methodology
- Consultation closed 26th August
- Further changes identified as a result of consultation, discussions with Ofgem and further internal work
- These changes are just about complete in S West still working on S Wales

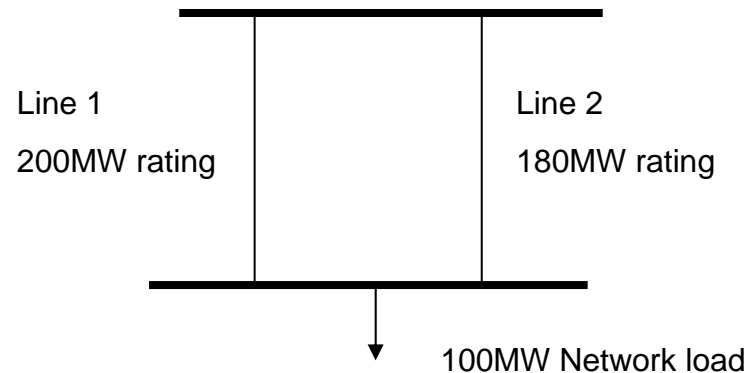
Areas where changes being made

- Calculation of security factors
- Treatment of off site sole use assets
- Treatment of contributions
- Calculation of Generator charges
- Scaling applied to generation charges
- Treatment of negative demand charges
- Transition arrangement for EHV Demand Customers
- In addition, presentation covers:
- IDNO charges (although we do not believe this will require a modification to the methodology)

Calculation of security factors

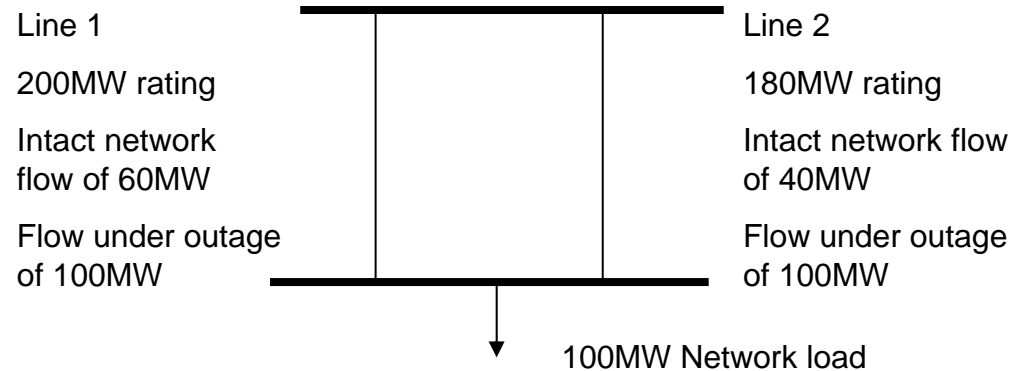
- July consultation – these factors were determined by Planning Engineers based on the configuration of the network and were incrementally increased to better reflect the actual conditions found
- This was an approximation and further work has found this to be too coarse and could cause price instability between years
- A simple (and exaggerated) example can show the issue and the solution

Security Factor Example



- July consultation
- In above example proposals assume a security factor of 2 for each line, hence reinforcement required in line 1 when load reaches 100MW and in line 2 when it reaches 90MW
- If uneven impedance between lines (and hence uneven loading) security factor increased in whole numbers to better represent load flows – this is an approximation
- The correct calculation of security factor is:
 - Highest flow through branch under worst outage ÷ intact network flow

Security Factor Example



	Line 1	Line 2
July security factor	2	2
Hence line loading requiring reinforcement	$200\text{MW} \div 2 = 100\text{MW}$	$180\text{MW} \div 2 = 90\text{MW}$
Correct security factor	$100\text{MW} \div 60\text{MW} = 1.66$	$100\text{MW} \div 40\text{MW} = 2.5$
Hence line loading requiring reinforcement	$200\text{MW} \div 1.66 = 120\text{MW}$	$180\text{MW} \div 2.5 = 72\text{MW}$

As a result we are now running a full contingency analysis to derive the correct security factors

Treatment of off site sole use assets

- July consultation – off site sole use assets included in LRIC calculation
- With some customers these off site sole use assets match their demand requirements and hence LRIC calculates a high price even though there is unlikely to be a growth in use of these assets
- DG incentive excludes sole use assets and hence it would be consistent to exclude these from the LRIC method.
- Hence off site sole use assets will be excluded from the LRIC calculation and treated the same way as on site sole use assets
- Whilst more cost reflective, this could cause step changes in price if new connection or disconnections result in sole use assets becoming shared or vice versa

Treatment of contributions

- July consultation – contributions were ignored in calculation of UoS prices at the EHV level – concern raised over double charging
- Under current connection arrangements, customers would pay for all sole use assets and a contribution to any upstream reinforcement
- Decided to assume that all sole use assets have been paid for via contributions and the only charges levied for these will be an annuity of their replacement cost.

Calculation of Generator charges

- July consultation – EHV generator charges based on the summer LRIC price and generators agreed export capacity. No change to the lower voltage methodology. Concern raised of lack of recognition of generation that defers winter reinforcement
- EHV generator charges to be calculated as follows:
 - For each branch used by the generation connection determine whether reinforcement driven first by winter or summer conditions
 - Where summer, branch price is summer price x agreed export capacity
 - Where winter, branch price is –ve of winter price x generator contribution to P2/6 security
 - Generator price is sum of branch prices
- £/kW to calculate HV/LV GDUoS prices reviewed to reflect costs seen
- 10% cap on price movements for HV and LV GDUoS retained due to the continuing low level of generation connections and hence volatility in income

Example of EHV calculation

- Assume a network with 3 branches – source node A, branches AB, BC, and CD with load and generation at node D

Generator 1

Capacity 50 MW
P2/6 Allowance 20 MW

	Winter Price £/kW	Summer Price £/kW	Charges
AB	10	5	-200
BC	20	5	-400
DC	5	10	500
Total			-100

Generator 2

Capacity 50 MW
P2/6 Allowance 0 MW

	Winter Price £/kW	Summer Price £/kW	Charges
AB	10	5	0
BC	20	5	0
DC	5	10	500
Total			500

Impact on transparency

- Proposed method is more cost reflective but....
- Price at a node will be different for generators with different P2/6 contributions to security
- Looking at the best way to publish prices

GDUoS at domestic level

- For domestic customers, WPD does not have a fixed charge and hence has the most microgenerator/energy efficiency friendly DUoS/GDUoS domestic tariffs in the UK as shown in the following table:

GDUoS at domestic level

Distributor	Fixed Charge (p/MPAN/day)	kWh charge (p/kWh)	Annual DUoS charge assuming 3,900kWh/year	Total DUoS/GDUoS charge with a 1kW microgenerator running for 30% of year (i.e. reducing consumption by 2,628kWh to 1,272kWh)	%age saving
CE (NEDL)	7.23	0.95	£ 63.44	£ 38.47	39%
CE (YEDL)	8.19	0.69	£ 56.80	£ 38.67	32%
CN (East)	5.54	0.77	£ 50.25	£ 30.02	40%
CN (West)	5.92	0.90	£ 56.71	£ 33.06	42%
EDF (Eastern)	4.96	0.911	£ 53.64	£ 32.14	40%
EDF (London)	3.72	1.119	£ 57.22	£ 30.26	47%
EDF(S East)	5.25	0.724	£ 47.40	£ 30.82	35%
SP (Manweb)	5.35	1.54	£ 79.59	£ 39.12	51%
SP (Scotland)	7.31	1.62	£ 89.86	£ 47.29	47%
SSE (Hydro)	4.729	1.946	£ 93.15	£ 42.01	55%
SSE (Southern)	5.041	1.258	£ 67.46	£ 34.40	49%
UU	4.95	1.15	£ 62.92	£ 32.70	48%
WPD (S West)	0.00	1.92	£ 74.88	£ 27.05	64%
WPD (S Wales)	0.00	2.24	£ 87.36	£ 31.67	64%

GDUoS at domestic level

- Despite the above, it is proposed that GDUoS prices associated with customers on profiles 1 to 4 are set to zero as no reinforcement costs are being incurred at present
- This will require a modification to our methodology statement as there is currently a limit of a 10% change in a 12 month period on these charges.

Scaling applied to generation charges

- Methodology can result in negative generation charges
- Price control incentive scheme is likely to be positive
- Hence a significant upward scaling of generation charges maybe necessary
- As it is possible that the total unscaled generator revenue could be negative only a £/kW type scaling can be guaranteed to work
- We are still assessing the options

Treatment of negative demand charges

- Whilst negative nodal prices can be caused by the change in flows resulting from adding a load, they are also caused by large generators that dominate the network exporting to the National Grid
- Such generators were generally connected prior to April 2005 and hence will not currently pay GDUoS charges
- As there will be no income from these generators and because of the concerns over negative demand charges raised in response to the consultation, it has been decided to cap the marginal part of the demand charges to zero

Transition of existing EHV Demand Charges

- A concern from the July responses is the step changes that some existing EHV demand customers will see on implementation
- Considering the following for the two years following implementation:

Charge in year t will be calculated as

$$D \times (0.5 \times C(t) + 0.3 \times C(t-1) + 0.2 \times C(t-2))$$

Where:

- D is the demand in year t for customer used in the calculation of the LRIC price.
- C(t) is the charge in year t expressed as a £/kVA after reconciliation to allowed revenue but before these transitional arrangement have been applied
- C(t-1) and C(t-2) are the actual charges applied in years (t-1) and (t-2) expressed as £/kVA

Impact on prices

- We do not yet have a full set of prices following the changes made following the consultation responses
- All areas of method currently being reviewed to understand any other significant simplifications
- One significant impact of the changes made is that the marginal LRIC prices are lower and hence the method of scaling used become more significant
- Whilst the last consultation specifically request views on the method of scaling, there were few responses and no consensus
- We have not made a final decision on how the LRIC prices will be reconciled to required revenue
- Following examples highlight the issue

Impact on prices (example)

- Target revenue from EHV network = £75m
- i) Marginal revenue recovery before reconciliation = £70m

Marginal cost before reconciliation	Method of reconciliation		Resulting charge for 50MVA customer	
	% scale	£/kVA shift	% scale	£/kVA shift
	7.1%	1.65		
Low cost node 7.71 /kVA	8.26	9.36	£ 412,809	£ 467,850
Average cost node 23.1 /kVA	24.77	24.77	£ 1,238,426	£1,238,426
High cost node 69.4 /kVA	74.31	71.00	£ 3,715,277	£3,550,154

- ii) Marginal revenue recovery before reconciliation = £30m

Marginal cost before reconciliation	Method of reconciliation		Resulting charge for 50MVA customer	
	% scale	£/kVA shift	% scale	£/kVA shift
	150.0%	14.86		
Low cost node 3.3 /kVA	8.26	18.16	£ 412,809	£ 908,179
Average cost node 9.91 /kVA	24.77	24.77	£ 1,238,426	£1,238,426
High cost node 29.7 /kVA	74.31	44.58	£ 3,715,277	£2,229,166

IDNO charges

- July consultation – no change to the treatment of IDNO charges
- Further work undertaken to investigate potential problems with the use of existing tariffs for IDNO networks supplying predominately domestic load
- We have no data on IDNO network load characteristics for housing developments and do not believe that weather corrected data that would align with other load research data used in tariff setting exists
- Using our LV network design tool (DEBUT), which uses load research data we have created some typical LV connected and HV connected housing estates and hence derived the overall characteristics

IDNO charges - example

- Taking a housing estate consisting of 50 houses – 43 of them off peak
- This would give an estate with a peak demand of 237kW at night – whereas a 50 house estate without off peak would have a peak demand of 66kW
- On a half hourly tariff, the availability charge is related to the maximum demand with the tariff method assuming this is a daytime MD
- Hence a half hourly tariff appears to be inappropriate for an off peak housing estate

IDNO Charges

- Yardsticks have been produced for predominately domestic IDNO networks. We are considering a tariff structure is used that matches that for profiles 1 and 4 (off peak customers)
- Such a tariff would comprise a day rate and a night rate only, and hence avoid the off peak demand issue resulting in a cost reflective tariff for both on and off peak housing estates
- Some concerns remain, for example were significant generation $>16\text{amp/phase}$ embedded in the network then such a tariff would not be cost reflective
- For predominately non-domestic IDNO networks (both LV and HV), the existing tariffs are cost reflective for the characteristics of these loads.
- The LRIC method uses the demand at the time of peak and hence gives a cost reflective charge at EHV

Forward timetable

- Not proposing to consult further
- Modification proposal will be sent to Ofgem as soon as we can
- If submitted in time, looking to implement from 1st April 2007 otherwise 4 months following approval
- If not vetoed within 28 days, submission into December can be consistent with a 1st April 2007 implementation
- If vetoed or not approved in time for a 1st April implementation, the existing methodology will continue to apply from 1st April 2007
- Regarding EHV prices, the existing methodology says *'For EHV sites it is proposed to set prices from April 2006 to the April 2005 price level adjusted by the change in RPI'*

Summary

- Account taken of the responses to the consultation with the following improvements to better meet the licence objectives:
 - Improved stability of prices
 - Better reflection of the costs/benefits of generators
 - More cost reflective treatment of sole use assets and contributions
- In addition:
 - Possible transitional arrangements for existing EHV demand tariffs proposed, and
 - Also looking at more cost reflective IDNO tariff
- Subject to submitting soon and Ofgem's response to a modification request, implementation could be from 1st April 2007

Any Questions

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