Deviations from Ofgem charging specifications – Part A: LRIC

Issue	Clause in Decision Document	Details in Decision Document	Clause in Methodology Statement	Details in Methodology Statement
Clarification of 'demand conditions' to be considered in powerflow analysis	1.6	Consideration of two 'demand scenarios' referred to as 'peak' and 'off-peak'	2.5	Maximum and Minimum Demand Scenarios considered (i.e. 'peak' and 'minimum' network loading conditions)
Clarification of treatment of partially completed projects in network representation to be considered in powerflow analysis	1.9	"The modelled network should be based on the network expected to exist and be in operation in the first regulatory year that charges are being calculated for" – but no guidance on treatment of projects expected to only be partially completed/ commissioned in the considered period.	Annex 1 4.3	Additional guidance: "Where a part of a single authorised network project is expected to be commissioned and operational in the year for which Use of System Charges are to be calculated then the DNO Party may, if appropriate, model the fully completed network project"
Level of generation export modelled in Minimum Demand Scenario	1.9	Full export capacity modelled for representation of generation in Minimum Demand Scenario (termed 'off peak' in decision document)	2.7 c)ii)	Application of Generation Coincidence Factor (representing the coincidence with all generation within each GSP group) to export capacity for representation of generation in Minimum Demand Scenario
Clarification of size of increment to be applied powerflow analysis	1.9	It was considered that the guidance within the decision document (below) could be interpreted in a couple of ways. "A ±0.1MW increment should be used in relation to calculating the active demand and generation elements of the incremental power flows, assuming that the power factor for demand is 0.95 and unity for"	2.7 b)	Clearer guidance stated: "A 0.1MW Nodal increment should be used in relation to calculating the active demand and generation elements of the incremented power flows, assuming that the power factor is 0.95 for increments applied at Nodes where demand is located and unity for increments applied at Nodes where generation is located. Increments will be applied in the direction of demand for the analysis of maximum demand network conditions and in the direction of generation for the analysis of minimum demand conditions."
Clarification on the conditions to be considered in the 'N-1' analysis used to derive Security Factors	1.9	Decision document states "Power flows under N-1 contingency conditions are used to calculate Security Factors."	2.7 c) v)	Additional guidance provided "Each N-1 Contingency will consider the consequential network actions and where appropriate constraints on customer demands (both generation and load) to meet the security of supply requirements of E/R P2/6."
Sense checking of the estimation of change in branch utilisation produced by application of Security Factors	1.9	No sense checking of the estimation of branch utilisation produced by application of Security Factors to Incremented Flows	2.7 d) & e)	Sense checking introduced with the following conditions identified: (i) low base power flows; (ii) high Security Factors; and (iii) where the difference between the base and incremented Branch power flows exceeds the change that could reasonably be expected to occur as a result of the application of an increment of demand or generation. Different approach to determining change in branch

				utilisation used where these conditions occur.
Statement of Incremental Cost	1.10	The incremental cost of reinforcing a node is the difference in the NPV of reinforcing it under base conditions and with an increment of demand or generation added.	2.8	The incremental cost of reinforcing a Branch due to an increment at a Node is the difference in the net present value (NPV) of reinforcing the Branch under base and incremented conditions.
Definition of Branch Capacity	1.12	No statement	2.9	***Branch Capacity*** is the MVA rating of the "critical" asset in the considered Branch divided by the corresponding Security Factor; a pair of Branch capacities is calculated for maximum demand and minimum demand conditions. Guidance on Branch ratings is provided in section. Guidance on sense checking Security Factors prior to the calculation of Branch incremental costs is provided in section.
Treatment of pair of incremental costs for node with both demand and generation	1.13	No statement	2.10	Additional statement 'Where both demand (load) and generation are located at a Node, separate incremental power flows shall be calculated using increments at 0.95 power factor and at unity power factor respectively.'
Sense checking of the cost recovery from the incremental costs associated with each branch	-	No sense checking of the overall recovery of incremental costs associated with each branch (leading to the recovery, in some cases, exceeding the branch reinforcement cost)	2.11-2.13	Introduction of sense checking of overall cost recovery from the incremental costs for each branch. Where overall cost recovery for a branch is considered excessive (greater than actual branch reinforcement cost), the overall cost recovery is limited to the actual branch reinforcement cost by application of a scaling factor
Clarification on the calculation of Nodal Charges	1.15 & 1.16		2.15 – 2.24	Greater clarification provided upon the calculation of Nodal incremental costs and marginal charges. Including:- - clarification that the period that drives reinforcement is the period with the higher absolute incremental cost - clarification that the calculation £/kVA/annum marginal charge requires the 'size of increment' to be taken account
Formulae of *IncrementalCostAtNode*	1.11	$IncrementalCostAtNode = \sum_{i=1}^{B} \Delta Ci$ Where ΔCi is the change in reinforcement costs of the asset in branch i when an increment of demand or generation is added to the node. B is the number of branches connected to the node.	2.17	$IncrementalCostAtNode^{Peak} = \sum_{i\in\alpha} s_i \cdot \Delta C_i^{Peak}, \alpha = \{1,2,...B \mid \lvert\Delta C_i^{Peak}\rvert > \lvert\Delta C_i^{Off-Peak}\rvert\}$ $IncrementalCostAtNode^{Off-Peak} = \sum_{i\in\beta} s_i \cdot \Delta C_i^{Off-Peak}, \beta = \{1,2,...B \mid \lvert\Delta C_i^{Peak}\rvert < \lvert\Delta C_i^{Off-Peak}\rvert\}$ where $\Delta C_i^{Peak} = [NPV(inc) - NPV(base)]_i^{Peak} \cdot AnnuityRate$ $\Delta C_i^{Off-Peak} = [NPV(inc) - NPV(base)]_i^{Off-Peak} \cdot AnnuityRate$

		$\Delta Ci = [Net\ Present Value(inc) - Net\ Present Value(base)] \times AnnuityRate$		ΔC_i^{Peak} ***and*** $\Delta C_i^{Off-Peak}$ ***denote the incremental cost of reinforcing Branch* i*, under maximum and minimum demand conditions respectively, due to an increment of demand or generation at the Node;*** s_i ***denotes the Recovery Factor for Branch* i*;*** **B** ***is the total number of Branches in the network;*** α and β are subsets of Branches where relevant conditions are satisfied.
Decomposition of Nodal Charges	-		2.25 – 2.27	Nodal charges split into 'Local' and 'Remote' elements
Calculation of Branch Charges	1.15/ 1.16	In the decision document reference is made to application of 'charging demand' to incremental costs to determine branch charges – which are then summated to create customers incremental charge	2.15-2.27	'Charging demand' is not applied to individual branch costs prior to summation of the the branch costs. Instead total Nodal marginal charges are calculated, which are then used in the calculation of the Tariff Elements by End Users (where account is made of chargeable demand/ capacity)
Output from LRIC Analysis	-	No statement	2.28	As statement, lists elements of LRIC methodology outputs

Issue	Clause in Decision Document	Details in Decision Document	Clause in Methodology Statement	Rationale for deviation
LRIC - Demand for charging purposes	1.19	"1.19. The demand used for charging purposes for connections to other licensed distributors needs further consideration by distributors as part of their development work for IDNO charging."		The proposed methodology calculates separate tariffs for each EDCM end-user on the LDNO's network. Each tariff would be calculated using a boundary equivalent capacity relating to that end user. Consequently, demand data relating to the connection is not required for charging purposes.
LRIC – Fixed adder approach	1.23 and 1.24	"1.23. In relation to EHV charges, a fixed adder revenue scaler should be used to ensure that EHV charges do not significantly over or under recover revenue. The adder will be in £/kVA."		The proposed method for demand scaling uses a site-specific approach. An EDCM demand revenue target is determined by splitting the DNO's allowed revenue between the EDCM and CDCM using site-specific notional assets and sole use assets as the allocation driver. Identifiable DNO cost elements of the target are allocated to EDCM customers using appropriate

				charge drivers. 80 per cent of the residual revenue is allocated to customers on the basis of site-specific notional assets. 20 per cent of the residual is allocated as a fixed adder charged on a combination of capacity and peak-time consumption. This approach is considered by the DNOs to be more cost-reflective than the pure fixed adder approach and minimises the risks of non-compliance with competition law.
LRIC – Final site-specific demand and generation tariffs	1.26 and 1.27	The final charges should consist of "the allocation of network rates and transmission exit charges" for demand and "the allocation of network rates, and where appropriate transmission exit charges" for generation.		The proposal for demand customers is to allocate direct costs, indirect costs, network rates and transmission exit charges before demand scaling. This makes the derivation of the final charge more transparent, reduces the proportion of EDCM demand revenue to be recovered through scaling and makes the charges more justifiable. For generation, the proposal is to recover direct costs and network rates relating to sole use assets only through the sole use asset charge. The generation revenue target is calculated by applying an O&M rate of £1/kW/year to the total EDCM pre-2005 generation capacity and adding that to the forecast DG incentive revenue for the charging year. No transmission exit charges are included for generation as there is no justification for charging generators for exit charges.
LRIC – Excess reactive charges	1.29	[The final charge] "needs to incorporate a reactive power charge for customers with a power factor worse than 0.95"		We do not propose an explicit charge for excess reactive power for demand or generation. This is because the FCP/LRIC active power unit rate is adjusted to take account of reactive flows relating to the customer. Including an explicit charge would result in double charging for reactive flows.

Deviations from Ofgem charging specifications – Part B: FCP

Issue	Clause in Decision Document	Details in Decision Document	Clause in Methodology Statement	Details in Methodology Statement
FCP load incremental charges	1.16	Formula could accommodate only a single reinforcement within a single network group	2.21-2.22	Formula revised to explicitly accommodate multiple reinforcements within a single network group
Sizing and installation of test-size generators (TSG)	1.20	A single type of TSG was defined. A relevant TSG was installed at the principal substation of each network group	2.14	Multiple types of TSG have now been defined. 'Substation' TSGs are now installed at source substations and 'circuit' TSGs are now installed around the perimeter of the network group.
Probability of connection of new generation	1.21	Probability implicitly based on a single type of TSG and installation at the principal substation in each network group	2.28-2.29	Probability now reflects the existence of multiple types of TSG and installation at multiple points in each network group
Time to reinforcement (generation)	1.23	Previous formula based on a single type of TSG	2.25	Formula now reflects the existence of multiple types of TSG
Total generation over the 10-year recovery period	1.24	Formula to calculate 10-year generation based on a single type of TSG	2.31-2.33	Formula to calculate 10-year generation now reflects multiple types of TSG and the revised probability of connection of new generation
FCP generation incremental charges	1.25	Formula based on a single type of TSG	2.34	Formula now reflects the existence of multiple types of TSG

Issue	Clause in Decision Document	Details in Decision Document	Clause in Methodology Statement	Rationale for deviation
FCP – Scaling	1.30	1.30. The charges described above are scaled by calculating a single fixed adder (£/kVA) in the following way:		The proposed method for demand scaling uses a site-specific approach. An EDCM demand revenue target is determined

		• A target income that relates to EHV assets is calculated by taking the total allowed revenue and splitting it by the proportion which the EHV modern equivalent asset value (MEAV) comprises the total network MEAV. • The total revenue recovered from FCP demand and generation EHV charges is deducted from the EHV target income to give a residual value. This is then divided by the total EHV kVA to give a £/kVA value which is incorporated into customers' final tariffs.		by splitting the DNO's allowed revenue between the EDCM and CDCM using site-specific notional assets and sole use assets as the allocation driver. Identifiable DNO cost elements of the target are allocated to EDCM customers using appropriate charge drivers. 80 per cent of the residual revenue is allocated to customers on the basis of site-specific notional assets. 20 per cent of the residual is allocated as a fixed adder charged on a combination of capacity and peak-time consumption. This approach is considered by the DNOs to be more cost-reflective than the pure fixed adder approach and minimises the risks of non-compliance with competition law.