CMP271 – Initial thoughts on residual cost recovery in a GB Demand Transmission Charge

DRAFT

Executive Summary

i. This paper considers the issues associated with the recovery of the allowed revenue for Transmission Owners through a GB demand transmission charge. Currently cost recovery is ensured through the addition of a residual component to the locational tariffs. This residual is material and increasingly significant in demand charges. Ofgem have highlighted that the residual may distort the electricity and capacity markets by creating excessive incentives to avoid costs for embedded generation and demand side response.

ii. In developing alternative approaches it is essential that they meet objective criteria for assessment. This paper reviews some of the work associated with tariff evaluation and suggests criteria that could be used for assessment. Alternative cost recovery charging arrangements including supplier capacity charges and supplier meter charges are assessed using these criteria. Further issues associated with the treatment of vulnerable customers, implementation timescales and the relevant charging entities are discussed.

----

1. Introduction

1.1. This paper provides initial thoughts on the nature of recovery of allowed transmission revenue through a GB demand transmission charge. In particular it considers the current methodology for cost recovery in Section 2 and the interaction between cost recovery and locational tariffs in Section 3. Possible additional tariff components to ensure transmission owner cost recovery are discussed in Section 4. Section 5 presents alternative approaches to ensure cost recovery and Section 6 considers the wider implications of these approaches. Section 7 concludes.

1.2. These are initial thoughts on the potential issues associated with the cost recovery of transmission owner revenues for the purpose of discussion at the CMP271 Working Group. The paper considers the residual component of the tariff separately from the locational component of the tariffs (see the CMP271 work streams A and B).

2. Background

2.1. The principles establishing the basis for ensuring that the GB Transmission owners recover the allowed revenue in GB electricity transmission tariffs are set out in Section 14 of the Connection and Use of System Code (CUSC). Locational tariffs are derived from a DC Load Flow model (the Transport Model) which implements the Investment Cost Related Pricing Methodology (ICRP) first introduced by National Grid in 1993/94. Recovery of the required revenue is part of the charging methodology and requires uplift of the locational tariffs.

2.2. The rationale for revenue recovery is expressed as follows in the CUSC:

"*14.15.130 The total revenue to be recovered through TNUoS charges is determined each year with reference to the Transmission Licensees' Price Control formulas less the costs expected to be recovered through Pre-Vesting* *connection charges. Hence in any given year t, a target revenue figure for TNUoS charges (TRR_t) is set after adjusting for any under or over recovery for and including, the small generators discount*".

2.3. The locational tariffs derived from Transport Model do not recover costs from users. Rather they reflect a marginal incremental cost signal on users. The CUSC recognises this and states that:

"*14.15.131 In normal circumstances, the revenue forecast to be recovered from the initial transport tariffs [ITT] will not equate to the total revenue target. This is due to a number of factors. For example, the transport model assumes, for simplicity, smooth incremental transmission investments can be made. In reality, transmission investment can only be made in discrete 'lumps'. The transmission system has been planned and developed over a long period of time. Forecasts and assessments used for planning purposes will not have been borne out precisely by events and therefore some distinction between an optimal system for one year and the actual system can be expected*".

2.4. To ensure cost recovery of the allowed revenue a residual component is added to the initial transport tariffs. This is stated in the CUSC as follows:

*"14.15.132 …in order to ensure adequate revenue recovery, a constant non-locational **Residual Tariff** for generation and demand is calculated, which includes infrastructure substation asset costs. It is added to the initial transport tariffs for both Peak Security and Year Round backgrounds so that the correct generation / demand revenue split is maintained and the total revenue recovery is achieved".*

2.5. The addition of the residual to the locational tariffs allows the "effective" final tariffs to be calculated for both generation and demand. This calculation is expressed in the CUSC Section 14.15.133 as follows:

14.15.133 The effective Transmission Network Use of System tariff (TNUoS) can now be calculated as the sum of the initial transport wider tariffs for Peak Security and Year Round backgrounds, the non-locational residual tariff and the local tariff:

$$ET_{Gi} = \frac{ITT_{GiPS} + ITT_{GiYRNS} + ITT_{GiYRS} + RT_G}{1000} + LT_{Gi}$$ and

$$ET_{Di} = \frac{ITT_{DiPS} + ITT_{DiYR} + RT_D}{1000}$$

Where

ET=Effective TNUoS Tariff expressed in £/kW (ET_{Gi} would only be applicable to a Power Station with a PS flag of 1 and ALF of 1; in all other circumstances ITT_{GiPS}, ITT_{GiYRNS} and ITT_{GiYRS} will be applied using Power Station specific data)

For the purposes of the annual Statement of Use of System Charges ET_{Gi} will be published as ITT_{GiPS}; ITT_{GiYRNS}, ITT_{GiYRS}, RT_G and LT_{Gi}

2.6. In this formula the following definitions are used:

- ITT means Initial Transport Tariff;

- RT_G means Residual Tariff for Generation
- GiPS means Generation Peak Security
- GiYRNS means Generation Year Round not-shared
- GiYRS means Generation Year Round Shared
- LT_{GI} means Local Tariff Generation
- DiPS means Demand Peak Security
- DiYR means Demand Year Round; and
- RT_D means the Residual Tariff for Demand

2.7. The residual tariff is adjusted to ensure the 27%:73% allocation of cost recovery to generation and demand, and to respect the 2.5euros cap on allowed cost recovery for Generation tariffs (this is a binding constraint for cost recovery from generation tariffs). The effective generation/demand split for cost recovery in 2017/18 (Dec forecast) is 14.6% from generation and 85.4% from demand.

3. The impact of the residual on demand locational charges

3.1. The demand residual has a material and significant effect on demand locational tariffs. This can be illustrated by reference to the 2017/18 tariffs (Table 1).

Table 1: Locational demand tariffs for 2017/18 – Dec Forecast

Zone	Zone Name	Total Demand Charge Base: Triad Demand (GW)	Peak Security Unadjusted Zonal Wtd Marginal (km)	Peak Security Transport Zonal Tariff (£/kW)	Year Round Unadjusted Zonal Wtd Marginal (km)	Year Round Transport Zonal Tariff (£/kW)	Residual Tariff (£/kW)	Final Zonal HH Tariff (£/kW)
1	Northern Scotla	0.923	-76.64	1.87	822.95	-20.11	47.98	29.75
2	Southern Scotla	3.109	-0.92	0.02	710.26	-17.36	47.98	30.65
3	Northern	2.267	109.32	-2.67	242.23	-5.92	47.98	39.39
4	North West	3.854	29.20	-0.71	75.87	-1.85	47.98	45.42
5	Yorkshire	3.566	105.43	-2.58	11.04	-0.27	47.98	45.14
6	N Wales & Mer	2.350	74.35	-1.82	-32.53	0.79	47.98	46.96
7	East Midlands	4.360	87.18	-2.13	-90.30	2.21	47.98	48.06
8	Midlands	4.125	57.72	-1.41	-125.02	3.05	47.98	49.63
9	Eastern	6.036	-42.63	1.04	-31.20	0.76	47.98	49.79
10	South Wales	1.657	253.13	-6.19	-160.60	3.92	47.98	45.72
11	South East	3.711	-157.88	3.86	-35.48	0.87	47.98	52.71
12	London	4.112	-206.46	5.05	-86.43	2.11	47.98	55.14
13	Southern	5.179	-68.74	1.68	-160.13	3.91	47.98	53.58
14	South Western	2.436	38.22	-0.93	-207.76	5.08	47.98	52.13
		47.684	201.27		932.92			

3.2. The data in Table 1 indicates that the residual component of the tariff has a key impact on the incentive properties of the locational tariff for users. For example, users benefit most from avoidance of the tariff by locating in southern Britain. However, the uniform application of the residual uplift ensures that the relative locational signals are preserved.

3.3. The application of the locational tariffs to the half hour/non-half hour supplier charging base, together with the adjustment for the small generation discount determines the actual final tariffs and associated incentives including tariff avoidance (Table 2).

Table 2: Final Half hour and Non half hour tariffs for 2017/18

Demand		Dec forecast	
Zone No.	Zone Name	HH Zonal Tariff (£/kW)	NHH Zonal Tariff (p/kWh)
1	Northern Scotland	30.395559	6.381455
2	Southern Scotland	31.298919	4.376830
3	Northern	40.041679	6.066212
4	North West	46.064536	5.985106
5	Yorkshire	45.785960	6.087929
6	N Wales & Mersey	47.610087	6.722479
7	East Midlands	48.708140	6.356156
8	Midlands	50.276580	6.533291
9	Eastern	50.436217	7.211672
10	South Wales	46.370777	5.879999
11	South East	53.356908	7.591258
12	London	55.789133	5.572371
13	Southern	54.224465	7.156419
14	South Western	52.774877	7.581867
	Tariffs include small gen tariff of:	0.647411	0.088128

3.4. Ofgem have noted[1] that the residual component of the tariff may result in distortions to the electricity market. Ofgem have highlighted that:

"With the increase in overall TNUoS charges and the rapid increase in the volume of EG [Embedded Generation], the size of TNUoS demand residual payments has grown as has the number of parties receiving them. This creates a large benefit to connecting to the distribution network rather than the transmission network".

3.5. Ofgem have indicated that:

"We are concerned that the size and increase of the TNUoS demand residual payments may now be distorting the market by:

- *leading to an inefficient mix of generation by encouraging investment in smaller distribution connected generation (which can take advantage of the embedded benefits revenue stream) over potentially more efficient larger transmission connected generators (TG) or over-100MW EG (which do not have that revenue stream);*
- *leading to TG exiting because it cannot compete;*
- *distorting dispatch by dampening prices at peak times when EG dispatch out of merit to generate in the triad periods;*
- *distorting the outcome of the capacity market (CM) by holding down prices since smaller EG can bid in at significantly lower prices than larger EG and TG; and*
- *distorting innovation in the market towards parties who can best capture this large payment".*

4. Recovering transmission owner costs

4.1. While the current methodology ensures that the transmission owners recover their allowed revenue, it has a material impact on the incentive properties of the tariffs (as

[1] For example see the Ofgem open letter on "Charging arrangements for embedded generation", 29th July 2016 at https://www.ofgem.gov.uk/publications-and-updates/open-letter-charging-arrangements-embedded-generation

noted by Ofgem[2]). The key question for this section is: What the appropriate methodology for ensuring that the transmission companies achieve their allowed revenue while ensuring the any associated market distortions are minimised.

4.2. There is a body of academic literature associated with electricity network cost recovery. This recognises the fact that marginal cost signals from network simulation models do not recover the actual costs of owning and operating an electricity network (actual investment costs and maintenance of the system). For example Perez-Arriaga et al (1995)[3] state that

"*Strict marginal network revenues (here renamed as variable charges) are clearly insufficient in practice to recover the network costs*"; and

"*In actual systems a mismatch exists between marginal network revenues and total costs, because of a number of reasons"…."They include discrepancies between static and dynamic optimal expansion plans, planning deviations and errors, the strongly discrete nature of investments, economies of scale, reliability constraints, other constrains on network investments*"

4.3. A useful summary of the issues associated with cost recovery of electricity network costs is provided by Brown and Faruqui (2014) in a report prepared by the Brattle Group for the Australian Energy Market Commission[4].

4.4. Brown and Faruqui (2014) identify a number of criteria that could be used to assess the effectiveness of the approach towards the recovery of network owners' costs. They cite the following:

"*Professor James C. Bonbright is the most widely quoted expert on the subject. In his text on public utility tariffs (Bonbright, 1961[5] and 1988[6]), he lays out ten principles for tariff design. These do not specifically focus on the pricing of distribution network services because when he was writing all utilities were vertically-integrated and distribution network services were not unbundled. Nevertheless, the ten principles noted below provide a framework within which distribution tariffs should be evaluated:*

1. *Effectiveness in yielding total revenue requirements, without encouraging undesirable over-investment or discouraging reliability and safety.*
2. *Revenue stability and predictability, with a minimum of unexpected changes that are seriously adverse to the utility companies.*
3. *Stability and predictability of the tariffs themselves, with a minimum of unexpected changes that are seriously adverse to utility customers.*
4. *Static efficiency, i.e., discouraging wasteful use of electricity in the aggregate as well as by time of use.*
5. *Reflection of all present and future private and social costs in the provision of electricity (i.e., the internalization of all externalities).*

---

[2] Ofgem Open Letter, op cit

[3] Perez-Arriaga I.J., Rubio F.J, Puerta J.F, Arceluz J. and Marin J, "Marginal pricing of transmission services: An analysis of cost recovery", IEEE Transactions on Power Systems, Vol.10 No1, February 1995 (Perez-Arriaga et al, (1995)).

[4] Brown T. and Faruqui A. (2014) "Structure of Electricity Distribution Network Tariffs: Recovery of Residual Costs", Report prepared by the Brattle Group for the Australian Energy Market Commission, August 2014. A link to the report can be found at http://www.brattle.com/news-and-knowledge/news/brattle-experts-prepare-report-for-the-australian-energy-market-commission-on-recovering-residual-costs-from-electricity-distribution-network-tariffs

[5] Bonbright, James C. Principles of Public Utility Rates, Columbia University Press, 1961.

[6] Bonbright, James C., Albert L. Danielsen and David R. Kamerschen, Principles of Public Utility Rates, Second Edition, Public Utilities Reports, Inc., 1988

6. *Fairness in the allocation of costs among customers so that equals are treated equally.*
7. *Avoidance of undue discrimination so as to avoid subsidising particular customer groups.*
8. *Dynamic efficiency in promoting innovation and responding to changing supply–demand patterns.*
9. *Simplicity, certainty, convenience of payment, economy in collection, comprehensibility, public acceptability, and feasibility of application.*
10. *Freedom from controversies as to proper interpretation".*

4.5. Brown and Faruqui (2014) conclude that in considering cost recovery the issues are as follows:

"We found the following principles to be relevant for structuring tariffs to recover residual costs.

- *The guiding principle in the academic literature is Ramsey pricing, or the "inverse elasticity" rule. Residual costs should be recovered from the various services provided by the firm and the various groups of customers served in inverse proportion to the respective price elasticity of demand. The intuition behind this rule is that the broader goal is to have efficient tariffs based on LRMC, and that departures from LRMC induce inefficiencies. The magnitude of the inefficiencies is minimized if the movement in prices away from LRMC is concentrated on those tariffs or parts of the tariff which have the smallest elasticities.*

- *In practice, utilities and regulatory authorities place significant weight on equity or "fairness" considerations. We found that the "fairness principle" is subject to multiple interpretations when it comes to tariff design. In one interpretation, fairness means that tariffs should not be changed so drastically that certain customers experience large bill increases in a short period of time while others experience large bill decreases. In a second interpretation, it means that a change in tariff design should not result in a significant change in the revenue recovered from any one class. And in a third interpretation, it means that all customers in a class should pay the same average tariff expressed in cents per kWh, $ per kW, or some combination thereof. Finally, there is the idealized theory of fairness and justice propounded by the late Harvard professor, John Rawls, regarded by many as the most significant philosopher of the twentieth century. One of the key elements of the theory is the Rawlsian concept of the "Difference Principle." Rawls argued that the greatest benefit should be accorded to the most disadvantaged members of society[7]. Those who advocate lower tariffs for vulnerable customers are knowingly or unknowingly citing the ideas of Rawls.*

- *Finally, the principle of "gradualism" suggests that tariffs should change gradually to reflect the long-term nature of investment in end-use electrical equipment, and the fact that such investment was made based on reasonable expectations about future tariffs. Gradualism avoids shocking and inconveniencing customers with sudden bill increases and simultaneously benefiting others with sudden bill decreases*".

[7] http://www.crf-usa.org/bill-of-rights-in-action/bria-23-3-c-justice-as-fairness-john-rawls-andhistheory-of-justice. Also see: http://plato.stanford.edu/entries/rawls/.

4.6. Brown and Faruqui (2014) consider a number of different approaches towards cost recovery based on some form of either:

- "**Ramsey" pricing**: based on "*charging different prices to different customer groups (or, in the case of multi-product or multi-service firms, charging different mark-ups over marginal cost on different products or services). Customers who are price inelastic are charged a higher price than those who are price elastic, and thus more of the residual costs are recovered from customers who are price inelastic than from the customers with elastic demand. This has come to be known as the inverse elasticity rule"*; or

- **Non-linear pricing:** based on "*a fixed charge and a volumetric charge which could be flat or have a block tariff structure (inclining or declining). The fixed charge would be designed to recover the fixed costs of generation, transmission and distribution while the volumetric charge would be designed to recover the variable costs of generation, mostly fuel, and possibly variable transmission and distribution costs (losses). If the appropriate metering infrastructure is in place, the volumetric charge could have a time-varying character which could either be static (e.g., two or three period time-of-use tariffs) or dynamic (e.g., critical peak pricing or real time pricing").*

4.7. The following section considers potential options for the recovery of GB transmission owner costs.

5. **Alternative approaches towards transmission cost recovery**.

5.1. This section considers possible approaches towards to recovery of the transmission allowed revenue in demand transmission charges. The starting point for this discussion is the proposal in CMP271 that the cost recovery element of the tariff is explicitly decoupled from the locational part of the tariff. Therefore this section only considers the revenue required to meet the "target revenue figure" for the transmission owners.

Option 1: Half hour charges for net supplier capacity and net non-half hour charges for supplier energy (using the 16:00-19:00 periods)

5.2. This option is based on the current approach towards the charging base which separates out the half hour and non-half hour charges. It is envisages that suppliers would be liable for a charge based on their half hour consumption at the peak (as a triad-based capacity charge) and a commodity charge based on supplier consumption in the 16:00 – 19:00 periods.

5.3. The principle drawback associated with this approach is the incentive properties created to avoid the charge for half hourly customers. Essentially the option replicates the problems associated with the current residual. Over rewarding peak embedded generation or demand reduction carries the risk of inefficient investment in the transmission system and distorts the electricity and capacity markets. In addition, the incentive properties are enhanced as customers transfer from non-half hour meters to half hourly meters, and the option does not address issues associated with "behind the meter" generation.

Variant 1a: Half hour charges for gross supplier capacity and gross non half hour charges for supplier energy (using the 16:00-19:00 periods)

5.4. This option is also based on the current approach towards the charging base but is based on **gross** half hour capacity and **gross** non half hour charges. It is envisages that suppliers would be liable for a charge based on their gross half hour capacity at the peak (as a triad-based capacity charge) and a gross commodity charge based on supplier consumption in the 16:00 – 19:00 periods.

5.5. The principle drawback associated with this approach remains the incentive properties created to avoid the charge particularly in this case for customers "behind the meter". Essentially this approach will still over reward certain peak embedded generation or demand reduction which carries the risk of inefficient investment in the transmission system and distortion in the electricity and capacity markets.

Option 2: Supplier charges based on annual energy consumption (The P271 proposal)

5.6. For simplicity the CMP271 proposal includes a potential approach towards cost recovery based on supplier consumption throughout the year. Essentially the approach would commoditise the residual as a £/kWh tariff. This approach is analogous to the approach adopted for Balancing Services Use of System (BSUoS) charges and would be relatively simple to implement using existing processes and systems.

5.7. The principal benefit of the BSUoS-type approach is that is significantly dilutes the embedded benefit by smearing the costs across all settlement periods in the year. However, this may over reward high load factor embedded which may have a significant cost advantage over transmission connected generation (there is an avoidable cost benefit). Nevertheless this approach may be better than the current baseline, which significantly over rewards embedded peak generation.

5.8. The potential issues associated with BSUoS charges have been highlighted by Ofgem in their open letter which stated that

"We have concerns that the BSUoS embedded benefit is likely to distort operational decisions (i.e. dispatch), by bringing some generators into merit at times when they should be out of merit (i.e. rendering it profitable for them to generate at times when otherwise it would not be profitable for them to generate)".

5.9. Ofgem have also noted the following with regard to the current BSUoS arrangements:

"However whilst we think there is a rationale for changing these charging arrangements, we do not currently think the BSUoS embedded benefit is a matter of similar priority to the TNUoS demand residual element of embedded benefit for the following reasons:

- *the BSUoS embedded benefit is smaller and hence causes less distortion to dispatch;*
- *it likely has a lower overall cost to consumers; and*
- *there are significant interactions with possible future development of local balancing which Ofgem is considering through our work on issues relating to Flexibility. We consider that these need to be thought through carefully and future work in this area scoped alongside other changes"***.**

Option 3: Supplier capacity charge

5.10. Under this approach suppliers would be subject to annual charges based on their year round capacity. Essentially annual consumption would be converted to a £/kW charge for suppliers. The actual tariff recovery would be subject to annual reconciliation.

5.11. This approach significantly dilutes any embedded benefits and is simple to implement. However it maintains the level embedded benefits based on avoided capacity charges, which may distort the wider electricity and capacity market. Over rewarding embedded generation and demand reduction may result in inefficient investment and issues associated with cross subsidy

Option 4: Supplier consumption class metering systems and consumption charge

5.12. This approach is based on the consumption class of supplier demand and the number of meters in a consumption class for each supplier. A fixed charge per meter for each supplier can be calculated

5.13. The approach can be illustrated by considering data[8] on the annual consumption of domestic and non-domestic customers in GB and the number of meters in each category (Table 3).

Table 3: Domestic and Non Domestic Consumption in GB

	Total Cosumption	Total Domestic Meters	Average Consumption per meter
2014 Figures	GWh	Thousands	kWh
Domestic	109,170	27,611	3,954
Non Domestic	186,150	2,436	76,402

5.14. Based on the data in Table 3 a charge per meter can be calculated by apportioning the total cost to be recovered by consumption class (in this case domestic/non domestic) and dividing the cost by the number of meters in each class (Table 4).

Table 4: Domestic/Non Domestic cost recovery through a meter charge for 2017/18 required revenue

	Required Residual Revenue	**Apportionment based on consumption**	**Charge Per Meter**
2017/18	**(£m)**	**£m**	**£**
Demand Cost Recovery	**2,288.12**		
Domestic		845.8	30.63
Non Domestic		1442.3	592.07

5.15. The Option 4 approach is illustrated by reference to domestic and non-domestic consumption classes. Clearly in calculating a Supplier's liability the approach could use the actual consumption classes used in settlement, the number of meters allocated to each consumption class and an adjustment to reflect outturn supplier demand. The approach could also provide adjustments to Supplier liabilities for

[8] "Sub-national electricity and gas consumption statistics", Department of Energy and Climate Change, 22 December 2015 at https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/527628/Sub-national_electricity_and_gas_consumption_summary_report_2014.pdf

customers that switch suppliers during a charging year. In addition suppliers could be billed daily for their liabilities and invoiced monthly in arrears.

5.16. The Option 4 approach has the benefit of relative simplicity in its application. In deriving a fixed charge per meter it removes any incentive properties associated with avoidance of the charge and better meets the principles of Ramsey pricing.

Merits of charging options

5.17. The relative merits of the charging options can be illustrated by reference to the Bonbright principles identified above. An evaluation for each option is illustrated in Table 5.

Table 5: Initial evaluation of Cost Recovery options by reference to the Bonbright (1961, 1988)[9] principles

Bonbright Criteria		Option1 Based on Current	Option 2 P271 - commodity	Option 3 Supplier Capacity	Option 4 Meters and consumption	Comments
1	Effective recovery					*Options 1-3 create incentives to avoid costs and over reward embedded*
2	Revenue Recovery					*All options are designed to ensure revenue recovery*
3	Stability, predictability					*All rely of some form of ex post adjustment for supplier volumes*
4	Static efficiency					*Option 4 is closest to Ramsey Pricing, all others createincentives to avoid costs*
5	Inernalise externalities					*Recovery of all transmission costs is ensured*
6	Fairness					*Option 1-3 may over reqard tarnsmission chagre avoidance (not cost reflective)*
7	No undue discrmination					*Certain customers can avoid costs under options 1-3, with cross subsidies*
8	Dynamic Effciency					*Option 4 is closest to Ramsey Pricing, all others createincentives to avoid costs*
9	Simplicity					*Option 2-4 are relatively simple but HH/NHH is more comlex*
10	Understandable					*Relatively simple and rules are clear for all options*

Fails to meet criteria		
Partially meets criteria		
Meets criteria		

5.18. Brown and Faruqui (2014)[10] suggest that the key tests for any change relate to Ramsey pricing; fairness and the nature of any implementation approach.

5.19. The following section considers further issues that may be taken into account in evaluating options for cost recovery under CMP271.

[9] Bonbright (1961) (1988) *op cit*

[10] Brown and Faruqui (2014), *op cit*

6. Further issues for cost recovery

6.1. This section considers further issues for cost recovery that arise as a result of CMP271 but which may be beyond the scope of the modification proposal and the CUSC.

Vulnerable Customers

6.2. As noted by Brown and Faruqui (2014), the recovery of transmission owner allowed revenue should be subject to a test of fairness in its application. In this context, the application of the cost recovery charge to certain classes of customer including vulnerable customers is relevant.

6.3. Given the impact of an additional charge on, for example, low income households, it may be considered appropriate to provide some form of relief for this class of customer. However, any relief from the supplier charge for vulnerable customers must be considered carefully since it would result in discriminatory treatment and some form of cross subsidy. The key question in the design of such arrangements is whether the discrimination can be justified (due discrimination).

6.4. The CUSC arrangements themselves are probably not the place to consider in detail the potential design of arrangements for the treatment of different classes of customers differently. The charging arrangements essentially relate to charges for suppliers without any differentiation or discrimination. In addition, the way that suppliers charge their customers is a matter for suppliers. However, it may be considered appropriate to develop some sort of arrangements for vulnerable customers under the terms of the supply licence. This is beyond the scope of this modification and is a matter for Ofgem and suppliers.

Implementation: cliff edge, delayed or gradual implementation

6.5. As noted by Brown and Faruqui (2014)[11] the approach towards implementation can be a significant consideration in the acceptability of any potential change in the tariff arrangements. There are a number of issues:

- A **cliff edge** approach may create issues for legitimate expectations associated with current approach towards tariffs and creates a risk of stranded assets. However, if the defect in the charging arrangement is material then it is imperative that the customer harm is addressed as soon as practicable;
- **Delayed Implementation** may allow users to adapt to a prospective change. The key issue for his approach is the duration of the delay and the potential customer harm that could occur as a result. It should be noted that it has been argued that there may be a requirement for some form of delay to allow users to adapt commercial arrangements and implement required system changes; and
- **Gradual implementation** implies some form of phased approach towards the change which could involve a hybrid approach towards the arrangements (part existing/part changed). Again the issue here is the duration of any phasing and the potential for customer harm arising from maintenance of the existing arrangements. A gradual approach could have a longer duration than a delayed implementation. However, phasing over a considerable time period would have the potential for a transition period that is unjustified (perpetual transition). In addition, the nature of any phasing arrangement would require

[11] Brown and Faruqui (2014), op cit

careful consideration (how would the current arrangements exist alongside the new arrangements) and certainly carries the risk of increasing the complexity of the charging methodology.

6.6. The approach towards implementation is an integral part of the CUSC modification process and will require careful consideration on the context of CMP271.

Supplier charges or Distribution charges?

6.7. The CUSC arrangements relate to the recovery of costs from suppliers. However, it may be appropriate to consider whether suppliers are the appropriate vehicle for the recovery of transmission costs. In this context, an alternative approach would be to recover the costs from Distribution Network Owners (DNOs) rather than suppliers. In turn DNOs could recover the costs from customers through the DNO charging arrangements.

6.8. Clearly and proposal for the recovery of transmission costs through DNO charges would require careful design in the DNO charging methodology. The considerations outlined elsewhere in this paper would come into play. At the moment DNO charges include fixed charged (standing charges) and some variable charges (time of use or commodity charges). The design of distribution tariffs to recover an additional £2-3bn of transmission costs is beyond the scope of the CUSC modification proposal (and this paper).

7. Conclusions

7.1. This paper has examined the issues associated with the recovery of transmission owner allowed revenues. The current approach associated with a residual uplift is unsustainable given the potential for distortion arising in the electricity and capacity market. However, the design of an alternative approach requires careful thought and a trade-off between simplicity of implementation and the risks of creating other potentially detrimental effects.

7.2. CMP271 has proposed that cost recovery should be achieved through a year round supplier commodity charge, reflecting the current BSUoS approach. While simple to implement this approach may create an unjustified incentive for cost avoidance. Alternative approaches based on supplier capacity may also have detrimental incentive properties. An alternative has been outlined based on a fixed per meter charge, and this may have some merits.

7.3. Further work is clearly required to consider the nature of the cost recovery arrangement for transmission owner costs. This should consider the effects of such arrangements on the incentive properties for cost avoidance provided to users connected to the transmission system

---

Bill Reed
RWE Supply and Trading GmbH

February 2017

Bill.reed@rwe.com

Annex A: Investment Cost Related Pricing (ICRP) methodology and demand tariffs

Introduction

A.1. The Investment Cost Related Pricing (ICRP) methodology introduced in 1993/94 is used to calculate transmission charges in Great Britain (GB). The charges are based on deriving the marginal investment cost of additional demand or generation using a DC Load Flow model (the Transport Model).

The Transport Model

A.2. The ICRP methodology considers the effects of an incremental MW at each node on the transmission system. This is achieved through increasing generation and demand at each node and identifying the incremental effects. The impact of the marginal MW is measured in "MWkm" (which can be positive and negative) for each node the Transport Model.

A.3. The marginal effects are categorised as related to either a "Peak Security" or a "Year Round" background, which reflect drivers for investment in transmission assets as set out in the National Electricity Transmission System (NETS) System Quality and Security Standard (SQSS).

A.4. The SQSS makes certain assumptions about the generation and demand capacity of each node on the system which are used in the Transport Model:

- The Peak Security scales "conventional generation" to meet ACS (average cold spell) peak demand (there is no contribution from "intermittent" generation capacity"); and
- The Year Round background assumes fixed scaling factors for "intermittent" generation and scales conventional generation to meet ensure that ACS peak demand is satisfied.

Transport Model Outputs

A.5. The output from the Transport Model is marginal MWkm grouped together into GSP Groups for demand and generation Zones for each background weighted by the relevant demand or generation capacity. Generation zones are based on grouping nodes that are electrically and geographically proximate using a fixed differential (+/-1.00kW) for the wider marginal costs.

A.6. The zonal tariffs are derived by multiplying the marginal MWkm by an "expansion constant" which reflects the assumed incremental costs per MW of transmission investment and a "security factor" that reflects the requirement network resilience (using the N-1 standard). The incremental MW and the derived £/kW tariffs for demand in 2017/18 are illustrated in Table A1.

Table A1: Demand tariffs in 2017/18[12]

Derivation of Zonal Demand HH Tariffs			Peak Security			
Zone	Zone Name	Total Demand Charge Base: Triad Demand (GW)	Peak Security Unadjusted Zonal Wtd Marginal (km)	Expansion Constant (£/MWkm) 13.575354	Locational Security Factor 1.8	Peak Security Transport Zonal Tariff (£/kW)
1	Northern Scotland	0.923	-76.64	-1,040.45	-1,872.81	1.87
2	Southern Scotland	3.109	-0.92	-12.52	-22.54	0.02
3	Northern	2.267	109.32	1,484.00	2,671.21	-2.67
4	North West	3.854	29.20	396.42	713.56	-0.71
5	Yorkshire	3.566	105.43	1,431.27	2,576.29	-2.58
6	N Wales & Mersey	2.350	74.35	1,009.29	1,816.72	-1.82
7	East Midlands	4.360	87.18	1,183.56	2,130.41	-2.13
8	Midlands	4.125	57.72	783.51	1,410.31	-1.41
9	Eastern	6.036	-42.63	-578.77	-1,041.79	1.04
10	South Wales	1.657	253.13	3,436.39	6,185.50	-6.19
11	South East	3.711	-157.88	-2,143.29	-3,857.92	3.86
12	London	4.112	-206.46	-2,802.83	-5,045.10	5.05
13	Southern	5.179	-68.74	-933.11	-1,679.61	1.68
14	South Western	2.436	38.22	518.83	933.90	-0.93
		47.684				

Derivation of Zonal Demand HH Tariffs			Year Round			
Zone	Zone Name	Total Demand Charge Base: Triad Demand (GW)	Year Round Unadjusted Zonal Wtd Marginal (km)	Expansion Constant (£/MWkm) 13.575354	Locational Security Factor 1.8	Year Round Transport Zonal Tariff (£/kW)
1	Northern Scotland	0.923	822.95	11,171.82	20,109.28	-20.11
2	Southern Scotland	3.109	710.26	9,642.03	17,355.65	-17.36
3	Northern	2.267	242.23	3,288.41	5,919.15	-5.92
4	North West	3.854	75.87	1,029.97	1,853.94	-1.85
5	Yorkshire	3.566	11.04	149.88	269.78	-0.27
6	N Wales & Mersey	2.350	-32.53	-441.54	-794.77	0.79
7	East Midlands	4.360	-90.30	-1,225.84	-2,206.52	2.21
8	Midlands	4.125	-125.02	-1,697.14	-3,054.86	3.05
9	Eastern	6.036	-31.20	-423.55	-762.40	0.76
10	South Wales	1.657	-160.60	-2,180.14	-3,924.24	3.92
11	South East	3.711	-35.48	-481.64	-866.95	0.87
12	London	4.112	-86.43	-1,173.33	-2,112.00	2.11
13	Southern	5.179	-160.13	-2,173.79	-3,912.82	3.91
14	South Western	2.436	-207.76	-2,820.41	-5,076.74	5.08
		47.684	932.92			

A.7. Based on the demand capacity and the transport tariffs an initial estimate of the revenue recovery through the locational tariffs can be derived from the model for each background. This is illustrated in Table A2 for the 2017/18 Demand Tariffs.

[12] The "Total Demand Charge Base: Triad Demand" is the peak demand on the transmission system for the purpose of setting tariffs

Table A2: Notional revenue recovery from demand locational tariffs using demand capacities

Derivation of Zonal Demand HH Tariffs				
Zone	Zone Name	Total Demand Charge Base: Triad Demand (GW)	Peak Security Transport Zonal Revenue (£m)	Year Round Transport Zonal Revenue (£m)
1	Northern Scotland	0.923	1.73	-18.57
2	Southern Scotland	3.109	0.07	-53.96
3	Northern	2.267	-6.06	-13.42
4	North West	3.854	-2.75	-7.15
5	Yorkshire	3.566	-9.19	-0.96
6	N Wales & Mersey	2.350	-4.27	1.87
7	East Midlands	4.360	-9.29	9.62
8	Midlands	4.125	-5.82	12.60
9	Eastern	6.036	6.29	4.60
10	South Wales	1.657	-10.25	6.50
11	South East	3.711	14.32	3.22
12	London	4.112	20.74	8.68
13	Southern	5.179	8.70	20.27
14	South Western	2.436	-2.27	12.37
		47.684	**1.96**	**-14.33**

Charging Methodology

A.8. For the purpose of applying the tariffs to Supplier demand in the charging methodology under the CUSC, the zonal demand locational tariffs in the model are combined for each zone (peak and year round locational tariffs are added together). The effect of the combined locational tariff using the demand capacity methodology on revenue recovery is illustrated in Table A3.

Table A3: Notional zonal demand revenue recovery in 2017/18 (excluding the residual component of the tariff and based on the current charging methodology)

Derivation of Capped Zonal Demand NHH Tariffs			Final HH Demand Tariffs	
Zone	Zone Name	Total Demand Charge Base: Triad Demand (MW)	Final Zonal Tariff (£/kW)	Final Zonal Revenue Recovery (£m)
1	Northern Scotland	923.39	-18.24	-16.84
2	Southern Scotlan	3,109.18	-17.33	-53.89
3	Northern	2,266.99	-8.59	-19.47
4	North West	3,853.96	-2.57	-9.90
5	Yorkshire	3,565.78	-2.85	-10.15
6	N Wales & Merse	2,349.89	-1.02	-2.40
7	East Midlands	4,360.13	0.08	0.33
8	Midlands	4,124.58	1.64	6.78
9	Eastern	6,035.90	1.80	10.89
10	South Wales	1,656.54	-2.26	-3.75
11	South East	3,711.20	4.72	17.53
12	London	4,111.70	7.16	29.43
13	Southern	5,179.46	5.59	28.97
14	South Western	2,435.66	4.14	10.09
		47,684.35		**-12.37**

A.9. The final stage in the charging methodology is to adjust the locational charges to ensure overall cost recovery. This is through a “residual” adjustment to the tariffs (Table A4).

Table A4: Demand locational Tariffs and Residual Adjustment

Zone	Zone Name	Total Demand Charge Base: Triad Demand (GW)	Final Zonal Revenue Recovery (£m)	Residual Tariff (£/kW)	Residual Zonal (£m)	Final Zonal Tariff (£/kW)
1	Northern Scotla	0.923	- 18.24	47.98	44.31	29.75
2	Southern Scotl	3.109	- 17.33	47.98	149.19	30.65
3	Northern	2.267	- 8.59	47.98	108.78	39.39
4	North West	3.854	- 2.57	47.98	184.93	45.42
5	Yorkshire	3.566	- 2.85	47.98	171.10	45.14
6	N Wales & Mer	2.350	- 1.02	47.98	112.76	46.96
7	East Midlands	4.360	0.08	47.98	209.22	48.06
8	Midlands	4.125	1.64	47.98	197.92	49.63
9	Eastern	6.036	1.80	47.98	289.63	49.79
10	South Wales	1.657	- 2.26	47.98	79.49	45.72
11	South East	3.711	4.72	47.98	178.08	52.71
12	London	4.112	7.16	47.98	197.30	55.14
13	Southern	5.179	5.59	47.98	248.53	53.58
14	South Western	2.436	4.14	47.98	116.87	52.13
		47.684			**2,288.12**	

A.10. The tariffs are then applied to half hourly demand based on a "half hourly" p/kW tariff applied to system peak demand capacity measured across the three half hours in the winter separated by 10 days (the Triad demand) and a "non-half hour" p/KWh tariff based on supplier demand from 16:00 to 19:00 hrs every day over the financial year. (Table A5).

Table A5: Demand tariffs and revenue recovery 2017/18.

Derivation of Capped Zonal Demand NHH Tariffs

Zone	Zone Name	Total Demand Charge Base: Triad Demand (MW)	Chargeable HH Zonal Triad Demand (MW)	HH Zonal Triad Demand Revenue Recovery (£m)	Residual NHH Zonal Triad Demand (MW)	Required NHH Zonal Revenue Recovery (£m)	NHH Zonal 1600-1900 Demand (TWh)	NHH Zonal 1600-1900 Demand Share (%)	NHH Zonal Tariff (p/kWh)
1	Northern Scotland	923.39	- 668.025	-19.87	1,591.42	47.34	0.752253	3%	6.29
2	Southern Scotland	3,109.18	641.726	19.67	2,467.45	75.63	1.763499	7%	4.29
3	Northern	2,266.99	314.289	12.38	1,952.71	76.93	1.286790	5%	5.98
4	North West	3,853.96	1,174.622	53.35	2,679.33	121.69	2.063560	8%	5.90
5	Yorkshire	3,565.78	1,106.638	49.95	2,459.14	111.00	1.850096	7%	6.00
6	N Wales & Mersey	2,349.89	519.724	24.41	1,830.17	85.95	1.295523	5%	6.63
7	East Midlands	4,360.13	1,456.313	69.99	2,903.82	139.56	2.226530	9%	6.27
8	Midlands	4,124.58	1,400.271	69.49	2,724.31	135.21	2.097776	8%	6.45
9	Eastern	6,035.90	1,472.861	73.33	4,563.04	227.19	3.189258	13%	7.12
10	South Wales	1,656.54	554.199	25.34	1,102.34	50.40	0.870233	3%	5.79
11	South East	3,711.20	870.404	45.88	2,840.79	149.74	1.995657	8%	7.50
12	London	4,111.70	2,194.260	121.00	1,917.44	105.73	1.927899	8%	5.48
13	Southern	5,179.46	1,649.598	88.38	3,529.86	189.12	2.675603	11%	7.07
14	South Western	2,435.66	540.175	28.16	1,895.49	98.81	1.318527	5%	7.49
		47,684.35	**13,227.05**	**661.46**	**34,457.30**	**1,614.29**	**25.313203**		