Memorandum

TO: **SSE**

FROM: **FTI Consulting**

DATE: **19 November 2020**

RE: **Review of the CUSC modification proposal CMP353**

1. Introduction

1.1 Transmission Network Use of System (TNUoS) charges recover the cost of installing and maintaining the transmission network in England, Wales, Scotland and offshore. Broadly speaking, TNUoS charges are a combination of locational charges (reflecting the incremental cost of power being added to the system at different geographical points) and residual charges.

1.2 A key parameter of the locational (cost-reflective) element of TNUoS charges is the Expansion Constant (EC). The EC reflects the annuitized £/MW/km per annum cost of 400kV Over Head Line (OHL) and has a direct impact on the locational signal that network users face. The EC is set at the start of each Price Control period, based on the cost of network expansion projects built over the preceding ten years (with adjustments to reflect inflation).

1.3 The EC is projected to increase significantly - by 83% - from April 2021, based on the small number of (relatively high-value) network expansion projects that were built over the relevant reference period.[1,2]

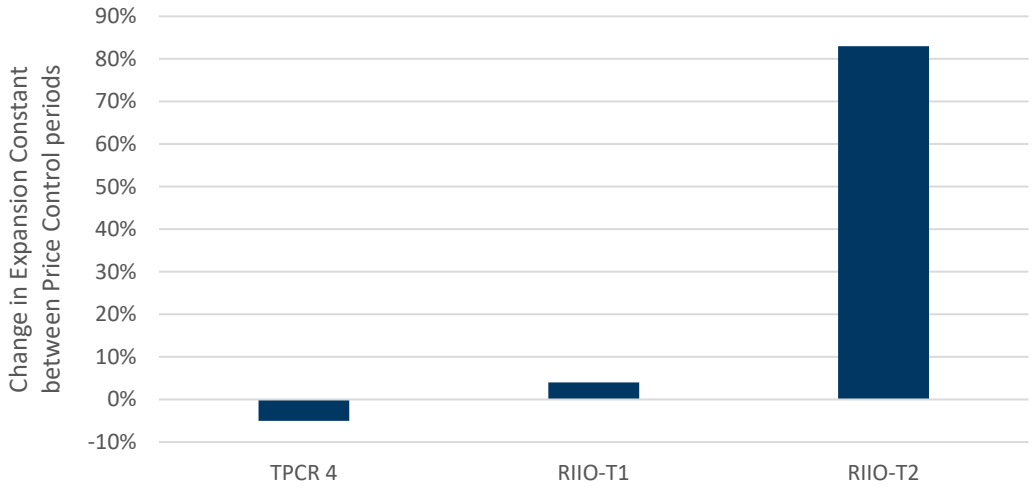
1.4 The projected change to the EC would be expected to have a very large impact on all users who pay TNUoS charges (and in particular the locational signals that users face in each of the 27 Generation Zones).

[1] The RIIO-T1 expansion constant value used in the calculation of the 2020/21 tariffs was set at £14.93/MW/km, whereas the RIIO-T2 expansion constant value is projected to increase by 83% to £27.38/MW/km. NGESO, CMP353 Proposal form, Oct 2020.

[2] Expansion Factors (EFs) are also expected to increase significantly, according to NGESO (NGESO, CMP353 Proposal form, Oct 2020). This memorandum focuses on the EC, since more information on this factor has been provided by NGESO to industry. Many of the points raised in this memorandum regarding the EC may apply to EFs as well.

1.5 The increase in the EC would be a much larger change than has been experienced previously, as shown in Figure 1-1 below, and arguably outside the bounds of what could be reasonably 'predicted' given historical variance.

Figure 1-1: Historical real-terms changes after recalculation of the Expansion Constant



Source: NGESO (2020), CMP214 Table A3 p. 42, June. NG (2013), Tariff Info Paper p. 7, April. NGESO, CMP353 Proposal form, Oct 2020. Note: Values are in 2012/13 prices. Conversion of data from CMP353 Proposal assumed to be in 2020/21 prices, deflated using a 2.6% inflation figure.

1.6 In light of this, and other concerns, the National Grid Electricity System Operator (NGESO) submitted Connection and Use of System Code (CUSC) modification proposal CMP353 on 29 October 2020.[3] The key concerns of NGESO, which we agree with and describe further in this memorandum, are that the expected change to the EC (and related Expansion Factors):

- *"may not truly reflect the current drivers of network investment";*
- *"will substantially change the locational costs for some Users";* and
- "*will present a cost shock to certain parties with little advance notice of the effects it will have on them*."

1.7 According to NGESO, the CMP353 modification proposal would "*stabilise the locational signal at the start of the RIIO-2 period at the RIIO-1 value plus relevant inflation in each charging year until such time as the effect of any change in the locational signal can be better understood*."

[3] NGESO, CMP353 Proposal form, Oct 2020.

1.8 On 2 November 2020, NGESO made a formal Request for Urgency in relation to the proposal[4], on the basis that an expedited timescale was required in order to allow resolution before the final TNUoS charges are published in January 2021. The Request for Urgency was granted by Ofgem on 3 November 2020[5].

1.9 In this context, SSE has asked FTI Consulting to review the impact of the existing method for the EC (i.e., the increase by 83%, which we refer to as the "Existing Method") and the rationale for the CMP353 modification proposal (which we refer to as the "CMP353 Proposal"). Our review is set out in this memorandum, which we have agreed that SSE may publish and/or share with stakeholders.[6]

1.10 The structure of this memorandum is as follows.

- First, we review the Existing Method against common network pricing principles and explain where there is the potential for the CMP353 Proposal to better meet those principles.
- Second, we perform a high-level indicative estimate of the quantitative impact of the Existing Method, on the basis that the regulatory uncertainty it creates may lead to a higher cost of capital for new and existing generators.
- Third, we review the CMP353 Proposal against the relevant objectives as defined in CUSC Condition C5 and explain that it performs well against the objectives.
- Finally, we explain why we consider the CMP353 Proposal is, in the round, beneficial to network users.

2. The case for change – assessment of the Existing Method against common network charging principles

2.1 Network charging is complex and often involves trade-offs between competing objectives. However, it is often valuable to review the appropriateness of a charging methodology by reference to certain principles, which, in the round, can lead to efficient economic outcomes.

4 NGESO, CMP353 Request for urgency letter, Nov 2020.

5 Ofgem, CMP353 Authority decision on urgency, Nov 2020.

6 Section 6 sets out relevant disclaimers to this memorandum.

2.2 There is no singular definitive formulation of network charging principles, but for the purposes of this exercise we use seven principles recently set out by the Council of European Energy Regulators (CEER). These principles were documented by CEER in relation to distribution charging, but they are principles that are also commonly used in transmission charging design and we have used similar principles in many engagements with and for GB regulators.

2.3 The seven principles are as follows:[7]

- **Cost-reflectivity.** For efficient use and development of the network, as far as practicable, charges paid by network users should reflect the cost they impose on the system and give appropriate incentives to avoid future costs.
- **Non-distortionary.** Costs should be recovered in ways that avoid distorting decisions around access to and use of the network, and market offers.
- **Non-discriminatory.** There should be no undue discrimination between network users.
- **Cost recovery.** Network owners should be able to recover efficiently incurred costs.
- **Transparency:** Network charges and the methodologies to calculate them should be transparent and accessible to all stakeholders.
- **Predictability:** It is important that network users can effectively estimate the costs of their use of the network, facilitating efficient long-term investment by network users. However, the changing nature of the energy system means charges will need to evolve over time.
- **Simplicity:** As far as possible, tariffs should be easy to understand.

2.4 Commentary on each of these principles is set out in the sub-sections below.

Cost-reflectivity

2.5 Cost-reflectivity is one of the most important network charging principles, and can contribute towards ensuring economically efficient decision-making. In energy networks, locational signals are a very important aspect of this.

2.6 We (FTI Consulting) have consistently advocated for careful consideration of ways in which energy markets globally might more accurately reflect appropriate locational signals to improve consumer outcomes.

[7] CEER, CEER Paper on Electricity Distribution Tariffs Supporting the Energy Transition, 20 April 2020.

2.7 While TNUoS charges are unlikely to perfectly reflect the full locational marginal costs of generation at a particular node, they do include a locational element whose purpose is to broadly reflect the transmission costs of a given geographic location. The key benefit of this form of locational pricing is that it has some impact on siting and closure decisions and in turn the demand for transmission. An effective cost reflective signal should, in turn, lower the overall cost of meeting energy demand, providing benefits to society.

2.8 With this in mind, we recognise there is, in principle, a need for the EC to be updated over time, as is the case with other inputs to the charging methodology. This is because changes in input costs and project efficiencies need to be reflected – if this were not the case, then signals could diverge further and further from reality.

2.9 However, it appears to us there is room for reasonable doubt as to whether the EC expected under the Existing Method is reasonably cost-reflective. This is because:

- The EC would be calculated based on "*higher value projects than in previous price controls*" as NGESO describes it. It is not clear whether such projects are representative of future expected transmission costs.
- The EC would be calculated based on "*fewer*" projects than in previous price controls. This is important because the smaller number of projects reduces the reliability of the data set as it is more strongly influenced by individual project costs.

2.10 Therefore, leaving aside the significant magnitude of the expected change in the EC under the Existing Method, and the opacity of the process (both discussed below), it seems to us it would be in line with good regulatory practice to explore the methodology further.

Non-distortionary

2.11 The principle of non-distortionary network charging is very closely linked to the principle of cost-reflective charges. This is because it is appropriate and efficient for network charges to differ between network users to reflect differences in the costs they impose on the network.

2.12 The locational factor in TNUoS charges provides a signal for where generation should be constructed. While TNUoS charges are just one element in a generators' business case (alongside other factors such as the availability of resource, planning consents, and the costs of land, fuel and labour), generators have no control over the future levels of the charges. At the margin, if the EC was materially higher or lower than the actual costs it is intended to reflect, then this could in principle distort generation siting decisions.

2.13 As well as providing an opportunity to further examine the cost-reflectivity of the EC methodology, the CMP353 Proposal provides an opportunity for stakeholders to fully consider the system-wide implications of this element of the methodology and, if necessary, develop a solution which leads to more appropriate locational signals.

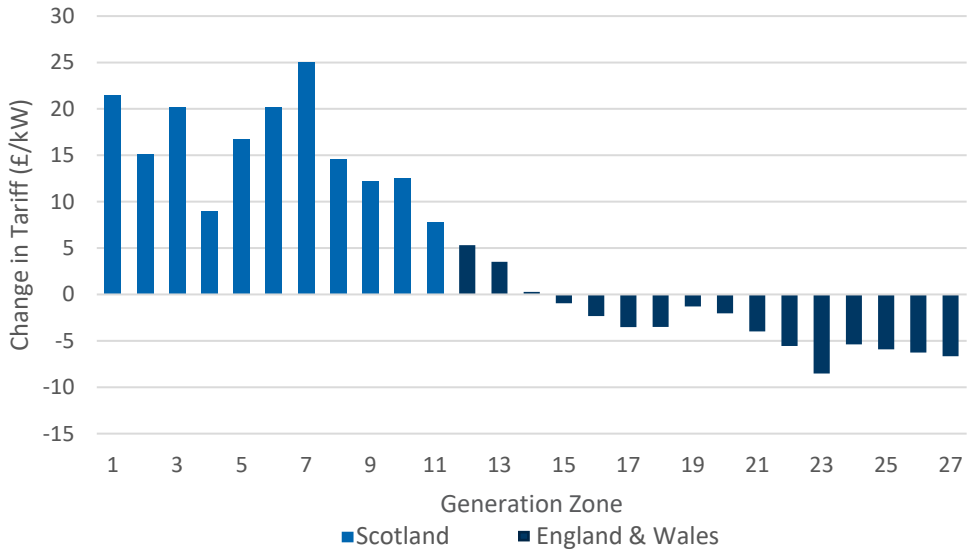
Non-discriminatory

2.14 The principle of non-discriminatory network charging is also very closely linked to the principle of cost-reflective charges. This is because it is not appropriate for network charging to unduly discriminate between network users, in ways which are not justified by differences in the costs which they impose on the network.

2.15 The way TNUoS charges are constructed means that the EC has a very significant differential impact on network users.

2.16 The geographical concentration of this impact can be seen below in Figure 2-1, which illustrates, for each Generation Zone, the change in TNUoS charge (averaged across three example tariffs[8]) as a result of the expected EC.

Figure 2-1: Change in tariff by Generation Zone (averaged across example tariffs) (£/kW)



Source: Average difference using NGESO's CMP353 proposal Tables 11 and 12. Broadly speaking, this reflects the expected difference between the CMP353 Proposal and the Existing Method.

2.17 As shown in Figure 2-1, every Generation Zone in Scotland experiences a higher cost uplift than any zone in England or Wales. Further, all but two Generation Zones in England and Wales would experience a lower charge under the Existing Method than they would under the CMP353 Proposal.

[8] NGESO presented three example tariffs in its proposal. These were for Conventional Carbon with 80% load factor, Conventional Low Carbon with 80% load factor and Intermittent with 40% Load Factor.

2.18 The impact of the Existing Method would therefore be to concentrate a relatively high increase in charges in a relatively small proportion of the generation capacity[9], all in one country (Scotland). There is a high potential for the methodology, *if not cost-reflective,* to produce unduly discriminatory outcomes. Given this, and the uncertainty described above regarding the cost-reflectivity of the new EC value, it would be in line with good regulatory practice to delay the implementation of this whilst exploring further the suitability and appropriateness of the methodology.

Cost recovery

2.19 An important principle of network charging is that network operators should be able to recover efficiently incurred costs. Our understanding, based on information published in NGESO's proposal, is that the Existing Method and the CMP353 Proposal would both meet this objective and there is no change to the overall cost recovery of network operators.

Transparency

2.20 The Existing Method does not appear to reflect a transparent methodology, because network users do not have access to any constituent elements driving the calculation of EC and Expansion Factors in advance. This has several implications:

- In the short term, the lack of transparency leads to users needing to request urgent modifications such as the CMP353 Proposal to avoid any unintended consequences.
- In the long term, a lack of transparency reduces the extent to which industry stakeholders can engage with, challenge and refine the methodology over time.
- In the long term, a lack of transparency can also impact the decisions of stakeholders as they are unable to fully understand how network charges are set. This increases the uncertainty faced by stakeholders affecting investment decisions.
- Following on from this, a lack of understanding of how the network charges are set makes it more difficult for network users to *predict* how network charges will evolve in the future. Where network users understand the methodology, they are better able to form views as to the evolution of network charges and in turn how they can reflect them in their pricing structures.

2.21 The CMP353 Proposal, whilst relatively simple, is transparent insofar as all network users can understand the rationale for and the relatively simple calculation of the 'rolled-over' EC. Further, it also provides the opportunity for greater transparency of and stakeholder engagement with the enduring nature of the EC methodology.

[9] Across all transmission-connected generation, approximately 8.5% of capacity is in zones 1-8 (Scotland).

Predictability

2.22 Predictability means that network users are better able to understand their risks and plan accordingly. This reduces uncertainty associated with investments, and in turn the cost of capital. This reduces costs and barriers to entry, contributing to greater competition and better outcomes for consumers in the form of lower prices and better service.

2.23 In network charging, a balance needs to be struck between allowing charges to 'evolve' with changes in underlying conditions, while at the same time affording a degree of stability. One reason for stability is that it allows network users to predict their charges. As an example of this, *within* Price Control periods, the EC is typically indexed to inflation each year, which typically results in more stability than if it were to be re-calculated each year based on new data.

2.24 *Between* Price Control periods, there is obviously more scope for change. However, the large increase in the EC under the Existing Method is a significantly larger change than has been experienced previously. The last two changes in the EC between price control periods (in real terms) were approximately -5% (in April 2007) and +4% (in April 2013).[10] Under the Existing Method, the equivalent change for April 2021 would be +83%. On the face of it, this is arguably outside the bounds of what could be reasonably 'predicted' given historical variance. Table 2-1 below sets out these changes.

Table 2-1: Historical real-terms changes of Expansion Constant

Parameter	BETTA (Apr 05)	TPCR 4 (Apr 07)	RIIO-T1 (April 13)	RIIO-T2 (Apr 21)
Expansion Constant (£/MWkm)	12.35	11.72	12.16	22.29
29Change in EC between price controls	-	(5%)	4%	83%

Source: NGESO (2020), CMP214 Table A3 p. 42, June. NG (2013), Tariff Info Paper p. 7, April. NGESO, CMP353 Proposal form, Oct 2020. Note: Values are in 2012/13 prices. Conversion of data from CMP353 Proposal assumed to be in 2020/21 prices, deflated using a 2.6% inflation figure.

2.25 The adoption of the CMP353 Proposal would obviously result in more predictable network charges in the short term. There is also, through stakeholder engagement, an opportunity for future methodologies to incorporate mechanisms to increase the predictability of changes to the EC (such as allowing for longer lead times, or smoothing, etc.)

[10] NGESO, CMP214 Table A3 p. 42, June 2020.

Simplicity

2.26 Overall, the TNUoS charging methodology is necessarily complex, and the methodology for determining the EC and related Expansion Factors is part of this larger process. Nevertheless, adoption of the CMP353 Proposal would be a relatively simple change and would result in the continuation of a well-understood inflation factor to apply in the short term.

2.27 As is the case with other principles, the CMP353 Proposal presents an opportunity for stakeholders to consider whether there are ways for a future methodology to more closely align with this principle and consider the trade-offs required to do so.

2.28 However, a more pertinent factor is that the charging methodology as a whole is due for review in 2023.[11] These changes will reflect the Targeted Charging Review with changes implemented from April 2021 and April 2022, as well as the Electricity Network Access and Forward-looking Charges Significant Code Review with changes expected from April 2023.[12] Additionally, there may be further changes arising from the Balancing Services Charges Task Force.[13] It may be simpler overall for stakeholders to understand, consider and engage with the EC calculation as part of a new charging methodology, rather than as an isolated change.

3. Illustration of quantitative impact of uncertainty faced by generators

3.1 The Existing Method represents a significant degree of uncertainty for network users. This is because the EC factor that materially affects the future costs of network users (and in particular, generators) is developed with an opaque methodology, and has now been shown to result in very large changes (which, in combination with other aspects of the methodology, results in extremely large changes in locational signals embedded in the TNUoS charges).

3.2 Any increase in the uncertainty and riskiness associated with assets will have an impact on the cost of capital, with investors *now* requiring a higher rate of return on *current* and *future* investments to compensate them for the increased riskiness. Increases in the cost of capital, in turn, can be passed on to consumers in the form of higher electricity prices. A related point was recognised by NGESO in its proposal, where it stated that uncertainty "*may cause Generators to apply risk premia in their contracts with Suppliers. Reducing this should lead to lower costs to consumers*"[14].

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11 Ofgem, Update on timing and next steps on Future Charging and Access reforms, 21 May 2019.

12 Ofgem, Update on timing and next steps on Future Charging and Access reforms, 21 May 2019.

13 Ofgem, Update on timing and next steps on Future Charging and Access reforms, 21 May 2019.

14 NGESO, CMP353 Proposal form p.6, Oct 2020.

3.3 It is difficult to quantify the impact that increased 'uncertainty' (of any form) has on the cost of capital.

3.4 However, to illustrate the order of magnitude of the impact, we have considered analysis undertaken by Ofgem as part of its mid-period reviews for RIIO-ED1 and RIIO-T1/GD1:[15]

- In this mid-period review, Ofgem used a 10-100bp increase in the cost of equity or 10-100bp increase in the cost of capital to reflect the impact of an increase in uncertainty.[16]
- Applying these figures to the asset base of the largest generator fleets in the UK[17] results in a total indicative increase in annual capital costs for these assets of between **£5 million** and **£84 million**.

3.5 Table 3-1 below and the associated notes explain this calculation.

Table 3-1: Illustrative estimate of increase in capital costs

		Cost of equity		WACC	
Line item	**Reference**	**Low**	**High**	**Low**	**High**
Impact from uncertainty	[A]	0.1%	1%	0.1%	1%
Gearing[1]	[B]	42%	42%	N/A	N/A
Impact on cost of capital	[C] = [A] × (1 – [B])	0.058%	0.58%	0.1%	1%
Generation assets, adjusted[2]	[D]	£8.4bn	£8.4bn	£8.4bn	£8.4bn
Impact on annual capital costs	**[E] = [C] × [D]**	**£5m**	**£49m**	**£8m**	**£84m**

Notes: [1]We estimate the gearing for generators by using SSE's gearing. We estimate SSE's gearing by dividing SSE's net debt (c. £10.5bn) as reported in SSE's 2020 financial statements by SSE's enterprise value (the sum of SSE's net debt and SSE's market capitalisation (c. £14.4bn) as of 13 November 2020) i.e. 10.5 ÷ (10.5 + 14.4) = 42%.[2] This reflects the book value of power generation assets as reported in the companies' financial statements. We have adjusted this figure by 50% to reflect that many generation sources are subject to subsidy mechanisms (such as Contracts-for-Difference) which materially reduce risk.
Source: FTI Consulting analysis using companies' financial statements and share price data from Bloomberg.

15 Ofgem, Decision on a Mid-Period Review for RIIO-ED1, 30 April, and Ofgem (2017), Mid-period review decision, 24 February 2018.

16 Ofgem, RIIO-ED1 Mid-Period Review Impact Assessment, 30 April 2018.

17 We estimate this impact by looking at the generation assets owned by the largest generators in the UK: EDF energy, Scottish power, SSE, Orsted UK, and Centrica.

3.6 Discounting by the social time preference rate of 3.5%,[18] this would result in an increase in the NPV of capital costs of c. £22-378m for existing generation assets over RIIO-T2.[19] If this increase in regulatory uncertainty persisted in perpetuity, we would see an increase in the NPV of capital costs of c. £139-2,390m for existing generation assets.[20]

3.7 These figures represent a large increase in the costs faced by generators and ultimately, consumers. These figures relate only to existing assets, and would be larger if also capturing the impact on future planned investments (which are, given the UK's 'Net Zero' ambitions, likely to be substantial and particularly so in the Generation Zones most sensitive to the EC).

3.8 Further, an additional impact from the increase in the uncertainty faced by generators could be fewer and/or smaller investments in generation than would otherwise be the case. This is because any increase in the cost of capital increases the probability that a given investment will not be projected to reach the 'hurdle rate' of that cost of capital.[21] The implications of this may be:

- consumers paying higher electricity prices than would otherwise be the case;[22] and/or
- putting at risk the UK's ability to meet its 'Net Zero' ambitions.

[18] HM Treasury (2018), The Green Book: Central Government Guidance on Appraisal and Evaluation, p.27-28.

[19] We estimate this by taking the estimated increase in capital costs from uncertainty for five years i.e. the length of RIIO-T2 and discounting using the social time preference rate.

[20] We estimate this by taking the estimated increase in capital costs from uncertainty and discounting them in perpetuity using the perpetuity formula: *Present value = capital costs / discount rate*.

[21] When choosing to invest, a key criterion for investors is the investment being able to meet its cost of capital. This decision rule for investing is sometimes referred to as net present value (NPV) being greater than or equal to zero. If the NPV of an investment is less than zero it implies the investment destroys shareholder value and should not be pursued. Therefore, any increase in the cost of capital increases this threshold for an investment.

[22] Electricity prices are determined by the interaction between the supply and demand of electricity. This interaction makes it difficult to predict the size of the impact of a reduction in supply on electricity prices. However, it is possible to predict the direction.

4. Assessment of the CMP353 Proposal against the CUSC Charging Objectives

4.1 In this section, we assess the CMP353 Proposal against the five objectives for tariff design set out in the Transmission licence standard Condition - Condition C5 (Use of system) charging methodology. These objectives are:[23]

- **Objective 1: Facilitates effective competition** in the generation and supply of electricity and (so far as is consistent in addition to that) promotes competition in the sale, distribution and purchase of electricity.
- **Objective 2: Results in charges which reflect, as far as is reasonably practicable, the costs** (excluding any payments between transmission licensees which are made under and in accordance with the STC) incurred by transmission licensees in their transmission businesses and which are compatible with standard condition C26 (Requirements of a connect and manage connection).
- **Objective 3: Properly takes account of the developments in transmission licensees' transmission businesses**.
- **Objective 4: Compliance with the Electricity Regulation** and any relevant legally binding decisions of the European Commission and/or the Agency.
- **Objective 5: Promoting efficiency in the implementation and administration** of the system charging methodology.

4.2 These objectives partially overlap with some of the principles we have described in Section 2 above.

[23] Ofgem, Transmission Licence Standard Conditions, 18 June 2020.

Objective 1: Facilitates effective competition

4.3 In our view, the CMP353 Proposal strongly meets the objective of facilitating effective competition. This is primarily for two reasons:

- As described in Section 2, it is likely to result in increasing transparency and predictability of network charges. This increases the confidence firms (and particularly generators) may have in planning for the future, which in reduces cash flow risk and lowers barriers to market entry (since smaller generators are, all else equal, exposed to more cash flow risk). The importance of mitigating cash flow risk was shown by Ofgem's recent regulatory decision in the face of Covid-19, where Ofgem limited the increase in BSUoS costs due to the impact from Covid-19 and also allowed the deferral of network charges payments.
- We would also note, as also described in Section 2, there is uncertainty as to whether the Existing Methodology does meet the objective of reflecting locational costs appropriately (and the CMP353 Proposal allows for this to be fully investigated). Cost-reflectivity supports network charges that are non-distortionary and non-discriminatory, which has the benefit of facilitating competition by allowing a level playing field between network users.

Objective 2: Results in charges which reflect, as far as is reasonably practicable, the costs

4.4 As explained in Section 2, the CMP353 Proposal does not have a material impact on the overall level of recovered transmission costs, which are assumed to reflect the efficiently incurred costs of the transmission operators.

4.5 However, as also explained in Section 2, due to the underlying evidence base used in the calculation of the EC it is uncertain whether the Existing Method leads to locational charges that are more cost-reflective. The CMP353 Proposal does not preclude the possibility of adopting the same EC as calculated under the Existing Method in future, but allows for further analysis of the changes which may lead to an EC that more accurately reflects the underlying expected costs over the future Price Control period.

4.6 The combination of the significant rapid *increase* in the EC under the Existing Method and reasonable doubt that the increased EC is truly cost reflective means that there is, on balance of probabilities, a significant upside to maintaining stability in the EC for a short period. On this basis, in the round, the CMP353 Proposal can better contribute towards meeting the objective of cost-reflectivity.

Objective 3: Properly takes account of the developments in transmission licensees' transmission businesses

4.7 As explained in Section 2, there is a strong rationale for updating certain parameters relating to network charges on a regular basis. However, in the case of the methodology underlying the EC, it is important to consider the wider context of charging design. Between April 2021 and 2023, there is expected to be large changes to the TNUoS methodology to reflect the Targeted Charging Review and Electricity Network Access and Forward-looking Charges Significant Code Review.[24] Additionally, there may be further changes arising from the Balancing Services Charges Task Force.[25]

4.8 It seems to us that, given these reforms, delaying any changes to 2023 would allow stakeholders to consider the impact of all changes in the round. The CMP353 Proposal would accommodate for this, thereby better taking account of developments in transmission.

Objective 4: Compliance with the Electricity Regulation

4.9 Our understanding is that the NGESO considers the CMP353 Proposal would have no impact on compliance with the relevant regulations.

Objective 5: Promoting efficiency in implementation and administration

4.10 As described in Section 2, adoption of the CMP353 Proposal would be a relatively simple change and would result in the continuation of a well-understood inflation factor to apply in the short term. The CMP353 Proposal also presents an opportunity for stakeholders to consider whether there are ways for a future methodology to more strongly adhere to the principle of simplicity. On this basis, the CMP353 Proposal contributes towards the principle of promoting efficiency in implementation and administration.

5. Conclusion

5.1 As set out above in this memorandum, the Existing Method presents three main challenges:

- a very large, rapid and unexpected *increase* in the EC;
- reasonable doubt that the resulting increase in this instance would be cost reflective; and
- a very significant distributional impact.

[24] Ofgem, Update on timing and next steps on Future Charging and Access reforms, 21 May 2019.

[25] Ofgem, Update on timing and next steps on Future Charging and Access reforms, 21 May 2019.

5.2 Further, whilst it is right that charging methodology parameters should evolve over time, the quantum of the increase is likely to introduce uncertainty to network users, which can increase the capital costs for network users such as generators.

5.3 Collectively, this means there is, on balance of probabilities, a significant upside to maintaining stability in the EC for at least a short period. The CMP353 Proposal achieves this, reducing the risk of introducing charges that are distortionary and unduly discriminatory.

5.4 In the meantime, as envisaged in the NGESO's proposal, further work can be carried out to examine the effects and suitability of the EC (and Expansion Factors). This further work could contribute towards increasing the transparency and predictability of charges in the future, and could be integrated with the wider review of transmission charging methodology that is proceeding in the sector.

5.5 Therefore, in the round, our view is that the CMP353 Proposal is likely beneficial for network users in aggregate, contributing towards many commonly-understood network charging principles and having a positive impact on all of the major CUSC Objectives.

6. Disclaimers

Restrictions

6.1 This memorandum has been prepared by FTI Consulting for SSE for the purpose described in Section 1 and no other party is entitled to rely on it for any purpose whatsoever.

6.2 FTI Consulting accepts no liability or duty of care to any person other than SSE for the content of the memorandum and disclaims all responsibility for the consequences of any person other than SSE acting or refraining to act in reliance on the memorandum or for any decisions made or not made which are based upon the memorandum.

6.3 Nothing in this memorandum constitutes investment, legal, accounting or tax advice, or a representation that any investment or strategy is suitable or appropriate to the recipient's individual circumstances, or otherwise constitutes a personal recommendation.

6.4 Other than for the purposes described above, this memorandum is not to be referred to or quoted, in whole or in part, in any registration statement, prospectus, public filing, loan agreement, or other agreement or any other document, or used in any legal, arbitral or regulatory proceedings without the prior written approval of FTI Consulting.

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6.6 No representation or warranty of any kind (whether express or implied) is given by FTI Consulting to any person as to the accuracy or completeness of the memorandum.

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