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Benefit-based remuneration of efficient infrastructure investments

Final report

For the European Union Agency for the Cooperation of Energy Regulators

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Abstract

The energy transition calls for a rapid expansion of electricity grids at both transmission and distribution levels. Technological progress and digitalisation offer new solutions to system needs that can increase the efficient use of existing and new electricity grids while reducing lead times. New regulatory approaches are needed to ensure that network companies are incentivised to explore and deploy these new solutions. This Report expands on previous research conducted by the FSR on behalf of ACER and its proposal for a benefit-based scheme to promote efficiency and innovation in addressing system needs by electricity transmission system operators. In particular, the Report provides additional implementation details of such a scheme and its most relevant design choices. It also offers an overview of regulatory practice in Europe, the USA and Australia with regard to the promotion of innovation and efficiency in transmission investments. Three sample cases illustrate how the proposed scheme could be implemented in practice. Finally, the Report summarises the results of a series of consultations, held with national regulatory authorities, transmission system operators and other stakeholders, where feedback was sought on the general features of the scheme and its main implementation aspects. While the implementation of the proposed scheme would not be without challenges, the Report suggests that those challenges are not much greater than those which are posed by the proper implementation of more traditional incentive-based mechanisms.

Keywords

Incentive regulation; electricity regulation; electricity grids; transmission system operators; national regulatory authorities; innovation in energy; efficient infrastructure investment; energy transition.

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While the report was commissioned by ACER, its content solely reflects the independent assessment of the authors, who are also the sole responsible for any errors or omissions.

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1 Introduction

The EU Agency for the Cooperation of Energy Regulators (ACER) commissioned the Florence School of Regulation (FSR) at the European University Institute to prepare a Report on Benefit-based remuneration of efficient infrastructure investments (the 'Report').

According to the Terms of Reference of this assignment, the Report should present the results of:

- Task 1: Mapping existing incentive schemes and evaluating their effectiveness in terms of the wide-scale deployment of cost-efficient alternatives to classical infrastructure solutions;
- Task 2: Stakeholders' consultation;
- Task 3: Develop examples of investments remuneration via benefit sharing and presentation of results.

This Report contains a description of all the activities performed by the FSR across the three tasks. It also provides a summary of the feedback received during the several rounds of consultations run over the course of the project.

However, before moving to the consideration of the three tasks listed above, it is useful briefly to describe the incentive-based scheme which the FSR outlined in a previous assignment[1] and whose implementation features are the focus of the current assignment.

The main features of such a scheme were presented at the 9th Energy Infrastructure Forum in Copenhagen in June 2023[2] and the scheme was fully described in a Report delivered to ACER in June 2023[3].

Therefore, this Report is structured as follows. Section 2 presents the current challenges in regulating network activities, and in particular investments in electricity transmission, which the proposed scheme aims to address. Section 3 outlines the main features of the incentive-based scheme to promote more efficient, innovative solutions to address system needs, proposed by the FSR in its previous assignment. This section also compares some characteristics of the proposed scheme with those of more traditional incentive-based regulation. The most relevant design choices and implementation challenges are discussed. Section 4 illustrates the activities carried out by the FSR in the context of Task 1: a mapping of infrastructure efficiency-related incentives in Europe is provided first; then a more detailed description of the incentive schemes implemented in five jurisdictions is offered, together with a reference to their performance assessment, where available. Section 5 illustrates the activities carried out by the FSR in the context of Task 2: the consultation with regulators and transmission system operators (TSOs) with regard to the general structure of the proposed scheme is described first; then the public consultation with stakeholders is presented. Section 6 illustrates the activities carried out by the FSR in the context of Task 3: three sample cases where the proposed scheme is applied are introduced first; then the consultation with regulators, transmission system operators and other stakeholders is illustrated. Section 7 concludes by summarising the key insights emerged during the project. Finally, in the annexes, additional details on the USA experience are provided, together with the text of the questionnaires used during the various consultations.

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1 Procurement procedure No. ACER/NEG/IGR/14/2023 (negotiated tender procedure) for drafting the main principles of benefit-based remuneration of efficient infrastructure investments for the European Union Agency for the Cooperation of Energy Regulators.

2 The presentation delivered by the FSR at the Forum is available at: https://circabc.europa.eu/ui/group/88886b79-cdea-4633-a933-8b191efb335b/library/f584257a-e4be-4a55-8c1d-dbbfdada8ca7/details.

3 FSR (2023), *Benefit-based incentive regulation to promote efficiency and innovation in addressing system needs*, June, available at: https://www.acer.europa.eu/en/Electricity/Infrastructure_and_network%20development/Infrastructure/Documents/Benefit_based_regulation_2023.pdf.

2 Current challenges in regulating investments in electricity transmission

The scheme proposed by the FSR aims at addressing the two aspects of the current regulatory setting which ACER identified as in need of improvement in its *Position Paper on incentivising smart investments to improve the efficient use of electricity transmission assets* of November 2021[4]:

- the capital expenditure (CAPEX) bias, which is the result of differences in the regulatory treatment of operational expenditure (OPEX) and CAPEX, creating a favourable environment to invest in CAPEX-heavy solutions; and
- the lack of incentives for TSOs to opt for more efficient solutions, including those at minimal (total) cost.

In fact, while the focus of network regulation is, *inter alia*, on promoting innovative and more efficient investments, system needs might also be addressed by solutions mostly based on changes in operational procedures, rather than on investments. Therefore, the aim of network regulation should be, more generally, to promote innovative and more efficient solutions to address system needs, rather than just innovative and more efficient investments.

The TOTEX approach, in which CAPEX and OPEX are treated symmetrically, has been proposed as a way of overcoming the CAPEX bias[5]. In its proper implementation, the TOTEX approach involves predefining a CAPEX-OPEX structure and remunerating the TSOs on the basis of this structure (therefore with a fixed ratio between the allowed revenues to cover OPEX – the 'fast' money – and the allowed revenues to cover CAPEX – the 'slow' money), irrespective of the solutions chosen and the actual cost structure of that solution. In such an implementation, the CAPEX bias is, in fact, overcome, but only within the regulatory period during which this CAPEX-OPEX structure is maintained constant. At the end of the regulatory period, the regulator is likely to revisit the CAPEX-OPEX structure, thus creating a sort of CAPEX bias again. Moreover, some of the implementations, while labelled as TOTEX, do not seem to keep the CAPEX-OPEX structure fixed, even within a regulatory period, thus completely failing to address the CAPEX bias.

Further considerations on how electricity transmission is regulated are presented in Section 4.1 below.

The *EU Action Plan for Grids*, presented by the European Commission in November 2023[6], confirms the relevance of the scheme proposed by the FSR. In this Communication, the Commission highlights, *inter alia*, the need to make better use of existing electricity grids and smarten them. This is essential to increase the ability of the system to integrate increasing amounts of renewable energy sources and accommodate the electrification of final energy uses, while limiting the overall level of investment required. According to the Commission, at the moment *"there are insufficient incentives for the uptake of smart grid, network efficiency and innovative technologies due to prevailing tariff structures with a focus on CAPEX"*. Moreover, *"insufficient compensation of OPEX as so far largely linked to human resource costs does not adequately reflect the rising costs of digitalisation, data processing or flexibility procurement"*.

In order to address this *"horizontal challenge"*, the Commission urges national regulatory authorities (NRAs) to *"regularly review their network tariff setting or methodologies, including how they […] incentivise the deployment of technologies that increase the efficiency and operability of the grids […], such as through*

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4 Available at: https://www.acer.europa.eu/sites/default/files/documents/Position%20Papers/Position%20Paper%20on%20infrastructure%20efficiency.pdf.

5 For a short introduction to the TOTEX approach, see von Bebenburg, C., G. Brunekreeft and A. Burger (2023), 'How to deal with a CAPEX-bias: fixed-OPEX-CAPEX-share (FOCS)', *Zeitschrift für Energiewirtschaft*, 47, 54-63.

6 EC (2023), *Grids, the missing link – An EU Action Plan for Grids*, COM (2023) 757 final, Brussels, 28 November 2023, available at: https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=COM%3A2023%3A757%3AFIN&qid=1701167355682.

output- or performance-based remuneration schemes". Indeed, according to the Commission, *"innovative approaches such as benefit sharing can contribute to energy system resilience at affordable prices"*. In this context, Action 8 of the Plan calls on ACER to *"further support NRAs through recommending best practices in the next tariff report due in January 2025 […] and subsequently support NRAs in their implementation"*.

3 The proposed scheme

In this section we outline the main features of the incentive-based scheme to promote more efficient, innovative solutions to address system needs, proposed by the FSR in its previous assignment. Some preliminary considerations, which contributed to shaping the initial proposal, are presented first. The details of the proposed scheme are then illustrated, together with its characterisation in the context of the regulatory practice. After that, three design choices are discussed in depth: the discount rate, the sharing factor and the incentive profile. A discussion of the challenges associated with the implementation of the proposed scheme concludes the section.

3.1 Preliminary considerations

In developing the proposal for an incentive-based regulatory scheme which addresses the concerns expressed by ACER, the FSR has considered that:

- While ACER refers to the opportunity of introducing benefit-based incentive regulation, the aspects referred to in Section 2 concern costs and the way in which they are allowed and rewarded under the current regulatory framework.
- A comparison between costs and benefits is the regular and traditional regulatory test for any investment or process in a regulated environment. The regulator should be satisfied that any investment or process proposed or undertaken by the regulated entities, and which is paid through the allowed revenues recognised to such entities, delivers positive net benefits, i.e. benefits higher than costs, to network users and, ultimately, to consumers, present and future.
- It is often true that benefits are more difficult to identify and uncertain than costs, as they depend, more than costs, on the future state of the world and of the system, and therefore are more difficult accurately to estimate and monetise[7]. Costs are typically easier to define. In approving new investments or processes, and the related allowed revenues, regulators can limit themselves to assess whether benefits exceed costs; they do not need to come to a precise assessment of the level of net benefits (unless financial constraints require some sort of ranking of investments and processes based on their net benefits[8]).
- At some stage, despite the inevitable uncertainties characterising the future and therefore the benefits which a proposed investment or process will deliver, the regulator(s) should 'take a view' as to the beneficial nature of such an investment or process and approve it. At that point, the costs of the proposed investment or process are included in the allowed revenues, as depreciation and return on capital, in the case of investments, and/or as allowed revenues to cover OPEX, in the case of processes. In this way, the TSO(s) would enjoy a cost-recovery guarantee and the risk of the world turning in a way of making the investment or process no longer beneficial is transferred from

[7] One type of benefit which could be, at least in part, easily monetised is represented by the congestion income related to an increase in the interconnection capacity between neighbouring market zones in the Internal Electricity Market. However, please note that:

a) the congestion income only represents part of the total benefits delivered by the increased interconnection capacity, as it does not fully include the changes in the (welfare) surplus enjoyed by market participants, and, correspondingly, it only provides an indication of the marginal value of the interconnection capacity once it is increased, and not of the value of such capacity increase;

b) the congestion income crucially depends on the difference in prices between the market zones connected by the interconnector and, therefore, might experience significant variations over time.

[8] However, even in this case, regulators need only to come up with the ranking of beneficial projects or processes on the basis of the net benefits which they deliver, and not with the exact and absolute valuation of such net benefits for each project or process.

the TSO(s) to the system. Leaving such a risk with the TSO(s) would increase the cost of capital[9]. The system is better placed to absorb such a risk.

- It seems to be too strict a regulatory approach to focus only on those system needs where benefits are easily quantifiable and monetisable. There might be other system needs which, if addressed, would be greatly beneficial for grid users and consumers, even though the benefits might not be easily quantifiable, let alone monetisable. However, these difficulties do not seem a good reason to neglect them.
- Since, as indicated above, benefits are typically difficult to estimate, translating them into a metric to define monetary incentives for the TSO(s) might be generally challenging.
- Finally, there is an asymmetry of information between the TSO(s) and the regulator(s) and the latter would have heavily to rely on the former for the assessment of the benefits to be delivered by the different possible investments and processes. There might therefore be a propensity for TSO(s) to over-estimate the benefits if such an assessment were to be used for determining the level of monetary incentives awarded to them.

3.2 The proposed approach at a glance

The proposed approach addresses the CAPEX bias and the general weakness of many regulatory frameworks to promote minimum-cost solutions at their root. It envisages incentives commensurate to a share of the difference between the allowed revenues required to cover the full costs of alternative solutions, assessed in net present value (NPV) terms. In this way, the composition of these costs is irrelevant and CAPEX and OPEX are treated in a fully symmetrical way.

It is important to emphasise that the proposed approach is not expected or intended to replace all existing regulatory frameworks and incentive schemes, but rather to provide regulators with an additional tool to overcome the CAPEX bias and other regulatory distortions promoting TOTEX-heavy solutions to system needs.

This said, the proposed scheme can be outlined as follows:

1) The regulator identifies the system needs to be addressed. This should be a general rule, as new investments or processes should always aim at addressing an identified need[10]. The TSO(s) might bring system needs to the attention of the regulator, but it is ultimately the latter that should confirm them.
2) The regulator defines a standard way of addressing each identified system need or set of needs. The consideration of sets of needs recognises the fact that some of such needs could be interlinked and addressing them as a set could be done at lower costs than aiming at the same needs separately. Again, the TSO(s) might assist the regulator in the definition of such a traditional standard solution. Academic studies or research reports could also be used for this purpose.
3) The regulator, possibly upon the proposal of the TSO(s), determines the prudently-incurred costs related to the traditional standard way of addressing the need or set of needs, the corresponding allowed revenues and the period over which such allowed revenues would be awarded[11]. These

[9] It is true, though, that low-cost investments typically involve a limited risk and processes might have a low share of sunk costs.

[10] In output-based or performance-based regulation, system needs are typically framed in terms of measurable output or performance. In the proposed scheme we prefer the more general reference to system needs.

[11] This could be according to the standard regulatory practices, for example of allowed revenues to cover CAPEX to be awarded for the length of the economic life of the assets.

costs would include OPEX and CAPEX. ACER's Unit Investment Cost indicators could also be used for this purpose[12].

4) The regulator also stimulates the TSO(s) to come up with a more efficient way of addressing the need(s), together with an estimate of the associated costs, which is presented to the regulator for its review and endorsement.
5) The incentive is then represented by a share (α) of any positive difference[13], in NPV terms, between the allowed revenues which would be required to cover the cost associated with the standard way of addressing the need(s) identified by the regulator and the allowed revenues which are required to cover the cost of the preferred, more efficient and innovative way identified by the TSO(s), where this difference is assessed over a time horizon equal to the economic life of the longest-living asset in the standard way of addressing the system need(s).
6) The incentive can be paid in annual instalments over a period (typically a few years) defined by the regulator.
7) Allowed revenues are then set to:
    - cover the costs of the more efficient, innovative solution proposed by the TSO(s), as defined by the latter in advance and endorsed by the regulator[14]; and
    - for the years over which the incentive is paid, the annual incentive instalment.
8) In case the solution proposed by the TSO(s) fails to address the identified system need(s), the incentive might not be paid and the allowed revenues might in fact be reduced to reflect the underperformance of the solution.
9) If the regulator also wants to incentivise the timely deployment of the new investments or processes, the scheme could be calibrated so that the incentive is reduced in case of delays in commissioning the new investments or in implementing the new processes, if such delays can be attributed to the TSO(s).

It is worth noting that the incentivising properties of the proposed scheme crucially depend on:

a) the regulator defining in advance the standard way of addressing the identified need(s) and the related costs and not adjusting the corresponding allowed revenues in response to the choices of the TSO;
b) the degree of benefit sharing determined by the regulator[15].

In particular, the higher the share of the cost saving awarded to the TSO(s) as an incentive, the stronger the inducement for the latter to seek lower-cost, more efficient solutions.

12 ACER's Unit Investment Costs indicators are updated every three years, pursuant to Article 11(9) of Regulation (EU) 2022/869 of the European Parliament and of the Council of 30 May 2022 on guidelines for trans-European energy infrastructure, amending Regulations (EC) No 715/2009, (EU) 2019/942 and (EU) 2019/943 and Directives 2009/73/EC and (EU) 2019/944, and repealing Regulation (EU) No 347/2013. The latest list of cost indicators, published in summer 2023 is available at:
https://www.acer.europa.eu/sites/default/files/documents/Publications/ACER_UIC_indicators_table.pdf.

13 Therefore, the overall allowed revenues would be capped at the level corresponding to the costs of the standard way of addressing the need(s) identified by the regulator.

14 In covering the costs of the more efficient, innovative solution, regulators might decide to keep the OPEX/CAPEX ratio fixed, as proposed by the TSO(s) in their application(s), thus implementing, for this part of the allowed revenues, the Fixed OPEX-CAPEX Share (FOCS) approach.

15 I.e., the share of the cost saving that the TSO(s) will be allowed to retain as incentives. The remaining part will be transferred to network users, and, ultimately, to consumers, through a reduction in network charges.

3.3 Characterisation of the proposed approach

There are several similarities between the implementation features and challenges of the proposed scheme and those of other incentive-based regulatory approaches, including the most traditional RPI-X approach[16].

For example, both the proposed scheme and traditional incentive-based regulation are based on the comparison of the actual performance of the TSO(s) with respect to some benchmark defined by the regulator – the X-factor as a measure of expected efficiency gains in traditional regulation, the traditional way of addressing the system need(s) in the scheme proposed here.

Moreover, the 'fixed OPEX-CAPEX share' (FOCS) approach, in which the regulator defines a fixed composition of CAPEX and OPEX in setting allowed revenues and keeps it fixed at least during a regulatory period, and which is a defining feature of a properly implemented TOTEX approach, could also be used to determine the component of the allowed revenues intended to cover the costs of the more efficient, innovative solution proposed by the TSO(s), thus providing the latter with ongoing incentives to work on the most efficient combination of OPEX and CAPEX for such a solution.

Finally, as with other incentive-based approaches, such as RPI-X regulation, the proposed scheme could also be used to prompt TSOs continuously to seek more efficient, innovative solutions to the identified need(s) and reveal the costs of such solutions. Eventually, these solutions may become the standard way of addressing the need(s) and be used as a reference by the regulators in subsequent regulatory periods.

3.4 The design choices for the proposed scheme

The implementation of the proposed scheme requires the regulator to decide on a number of design aspects:

- The discount rate to be used to obtain the net present values of the allowed revenues required to cover the costs of the alternative solutions to address the identified system need(s);
- The sharing factor, determining the share of the difference in the net present value of the allowed revenues between the two solutions, representing the cost saving delivered by the more efficient, innovative solution, which is left with the TSO(s) as an incentive;
- The time period over which the incentive is paid to the TSO(s) and the profile of such payments.

We consider these aspects in turn.

3.4.1 The discount rate

The more efficient, innovative solution to system need(s), which the proposed scheme is meant to promote, is likely to be characterised by a profile of costs, and therefore of allowed revenues, over time which is different from the profile of costs, and allowed revenues, of the traditional standard solution[17]. Therefore, one of the critical aspects in the implementation of the proposed regulatory scheme is the choice of the discount rate to be used in order correctly to compare, in net present value terms, the revenue requirement implications of the two solutions.

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[16] In the RPI-X approach, the allowed revenues for a regulated activity are set in advanced by the regulator for the length of the regulatory period, typically four to five years. In its simplest version, this approach assumes that allowed revenues change every year to cover the additional costs for the regulated firm due to inflation and to pass the benefits of increased efficiency to consumers. An inflation index, such as the retail price index (RPI), and an efficiency factor, usually indicated by X, are then used to adjust the level of allowed revenues from one year to the other. For more details on the RPI-X approach, see Rious V. and N. Rossetto (2018), 'The British reference model', in L. Meeus and J.-M. Glachant (ed. by), *Electricity Network Regulation in the EU: The Challenges Ahead for Transmission and Distribution*, Edward Elgar Publishing: Cheltenham, UK, 3-27.

[17] It is to be expected that the more efficient, innovative solution will be less CAPEX-intensive than the traditional standard solution and therefore the costs of the former will be more widely spread over time than the costs of the latter.

In reality, there are both an annuitisation and a discounting process to be performed in implementing the proposed scheme.

In fact, on the one side, the proposed scheme rests on the determination of the revenue requirements associated with both the traditional standard solution and the more efficient, innovative solution over the life of the longest-living asset which is part of the traditional standard solution. Regulation typically allows regulated companies to recover investment costs by including, in the revenue requirements, an annual element comprising depreciation (the return of capital) and the remuneration of the outstanding capital (return on capital). Such an annuitisation process should be performed using the weighted average cost of capital (WACC) which the regulator typically applies to the business under consideration.

On the other side, once the annual revenue requirements are determined (covering both the initial capital costs and the annual operating and maintenance costs) for both the traditional standard solution and the more efficient, innovative solution, they need to be discounted to obtain their net present values.

Such a discounting could be performed by using one of many possible discount rates, including:

- The WACC;
- The social rate of time preference (SRTP);
- The (real) discount rate of 4% recommended by ACER to be used for the cost-benefit analysis of energy infrastructure[18].

The SRTP is a measure of the society's willingness to postpone consumption now in order to consume more later. It is a relevant concept when it comes to comparing two different profiles of allowed revenues which would need to be collected from grid users. By paying sooner or later for the more efficient, innovative solution when compared with what they would otherwise have to pay, grid users would have to adjust their consumption (or savings) accordingly. In this respect, the SRTP seems to be the appropriate discount rate to be used to compute the net present values of the two profiles of the annual revenue requirements for the more efficient, innovative solution and for the traditional standard solution, respectively. The SRTP can be typically approximated by the after-tax rate of return on fixed-income government bonds, which raises at least the issue of the maturity of the government bonds taken as reference. However, a notion of government bond yield is implicit in the WACC used by regulators, as this includes a return on equity capital which, if determined by using the Capital Asset Pricing Model (CAPM), requires the definition of a risk-free (government bond yield) rate. Therefore, regulators could use the same notion of government bond yield as a proxy for the SRTP. On the other side, ACER has been recommending a 4% real discount since 2014[19]. The use of such a discount rate was first recommended by the European Commission in its Impact

[18] ACER (2023a), *Position Paper towards greater consistency of cost benefit analysis methodologies*, 22 March 2023, available at: https://www.acer.europa.eu/sites/default/files/documents/Position%20Papers/ACER_Consistency%20of%20CBA%20methodologies.pdf. In this paper, ACER "*recommends using the same social discount rate of 4%, already used by both ENTSO-E and ENTSOG CBA Methodologies".*

[19] ACER's *Opinion on the ENTSO-E Guideline to Cost Benefit Analysis of Grid Development Project*s of 30 January 2014, available at: https://www.acer.europa.eu/sites/default/files/documents/Official_documents/Acts_of_the_Agency/Opinions/Opinions/ACER%20Opinion%2001-2014.pdf. In that Opinion, ACER recommended the use of the 4% real discount rate (as a temporary solution) based on a 2012 Frontier Economics' study, which, in turn, refers to the European Commission's 2009 Impact Assessment Guidelines (see footnote **Errore. Il segnalibro non è definito.**).

Assessment Guidelines of January 2009[20]. A real discount rate of 4% seems to be in line with the discount factors used for energy projects in many other jurisdictions[21].

The SRTP is generally expressed in real terms, although the return on government bonds is paid in nominal terms. The discount rate proposed by ACER is a real rate. In fact, the analysis can be conducted either in nominal terms or in real terms, as long as it is done consistently in terms of the assessment of costs and the use of the discount rate.

WACC is instead a well-known regulatory concept, even though different regulators might use different financial market references for calculating it. Here again the analysis can be performed either in nominal terms or in real terms, as long as it is done consistently.

The SRTP is generally lower than the WACC, as it does not involve any reward for risk, beyond what is already incorporated in the rate of return on government bonds. In this context it is not obvious that, in comparing different profiles of allowed revenues which grid users would have to cover through grid charges, risk is a relevant consideration. The fact that risk should not enter this comparison seems to confirm the choice of the SRTP or of a discount rate reflecting government bond yields, as the best discounting factor. On the other hand, the advantage of the use of the WACC is that, in this case, the rate used to compute the component of the annual allowed revenues related to capital expenditure would be the same as the rate used for discounting such annual allowed revenues, making the computation slightly simpler.

3.4.2 The sharing factor

As highlighted in Section 3.2, the regulator would have to define the level of the sharing factor, which could range from 0 to 100%. It is clear that the higher the sharing factor, the greater the incentive for the TSO(s) to implement more efficient, innovative solutions, as a larger share of the cost savings with respect to the traditional standard solution would be retained by the TSO(s) as an incentive. However, the higher the sharing factor, the smaller would be the immediate benefits for grid users in terms of lower grid charges. Eventually, the more efficient, innovative solution will become the standard and grid users will fully benefit from the lower cost of such a solution.

In net present value terms, the immediate savings accruing to grid users are determined by:

$$Savings\ to\ grid\ users = (1 - \alpha) \times (C^* - C)$$

as long as $C < C^*$

where:

- C* is the net present value of the allowed revenues required to cover the capital and operating costs of the traditional efficient solution;
- C is the net present value of the allowed revenues required to cover the capital and operating costs of the more efficient, innovative solution; and

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20 European Commission's Impact Assessment Guidelines of 15 January 2009, available at: https://ec.europa.eu/smart-regulation/impact/commission_guidelines/docs/iag_2009_en.pdf. In point 11.6 of Annex A of such Guidelines, available as a separate document at https://ec.europa.eu/smart-regulation/impact/commission_guidelines/docs/iag_2009_annex_en.pdf, the Commission explains (in footnote 64) that the recommended 4% real discount rate "*corresponds to the average real yield on longer-term government debt in the EU over a period since the early 1980s*". The Commission also adds that "*for impacts occurring more than 30 years in the future, the use of a declining discount rate could be used for sensitivity analysis, if this can be justified in the particular context*".

21 See for example chapter 16 on "Current use of cost-benefit analysis" in OECD (2018), *Cost-Benefit Analysis and the Environment: Further Development and Policy Use*, OECD Publishing, Paris, available at: https://www.oecd-ilibrary.org/sites/9789264085169-19-en/index.html?itemId=/content/component/9789264085169-19-en.

- α is the sharing factor, i.e. the proportion of the net present value of the cost savings $(C^* - C)$ accruing to the TSO(s) as incentive.

It is conceivable that the higher the sharing factor, the more efficient and innovative would be the solution that the TSO(s) will come up with, and the lower the costs of such a solution. The relationship between α and C can therefore be generally expressed as:

$$C = C(\alpha) \; with \; C'(\alpha) < 0$$

Substituting this formulation for C in the expression for the savings to grid users, leads to:

$$Savngs \; to \; grid \; users = (1 - \alpha) \times [C^* - C(\alpha)]$$

A higher α will reduce the value of the first term in the product – the share of the savings immediately accruing to grid users; however, it will increase the second term – the potential savings obtained from the more efficient, innovative solution.

Therefore, in deciding on the level of the sharing factor, the regulator should consider the following trade-off:

- On the one hand, providing strong incentives to the TSO(s) so that the most efficient innovative solution is adopted, significantly reducing the cost of addressing the system needs;
- On the other hand, setting a sharing factor which is not too high, so that grid users immediately receive a sufficiently large share of the savings arising from adopting the more efficient, innovative solution, even before it becomes the standard one.

The optimal level of the sharing factor, considering this trade-off, depends on the extent to which a higher sharing factor would incentivise the TSO(s) to adopt even more efficient and innovative solutions, how much effort would be required for the implementation of such solutions and how much lower the costs of these solutions would be. *Ceteris paribus*, a higher sharing factor would provide greater incentives to the TSO(s) to adopt more efficient and innovative solutions. The same would be the case if such solutions did not require significant effort to be implemented or were characterised by much lower costs than the traditional standard solutions.

It is also possible to envisage a sliding sharing factor, i.e. a sharing factor which changes as the savings provided by the more efficient, innovative solution increase. In this respect, the sharing factor could be progressive – i.e. increasing with the savings – or regressive – i.e. decreasing with the savings. A progressive sharing factor might better compensate the TSO(s) for the greater effort required to implement innovative solutions characterised by much lower costs with respect to the standard solution. A regressive sharing factor may reduce the risk of an incentive payment to the TSO(s) which might be considered disproportionate in absolute terms.

Finally, it might be tempting to define the sharing factor in such a way that the incentive provided to the TSO(s) by the proposed scheme is comparable to the return on capital that they could obtain by investing in the traditional standard solution. However, it needs to be recognised that the incentive paid according to the proposed scheme and the return on capital on the traditional standard solution are of very different nature. The latter reflects the need for the TSO(s) to reward investors for the capital that they invest in the TSO business. It is therefore not ‘free money’ for the TSO(s). The incentive payment envisaged by the proposed scheme is, instead, ‘free money’, in the sense that it does not reflect, nor it is intended to cover any specific cost of the TSO(s). It rewards the greater effort of the TSO(s) in coming up with more efficient, innovative solutions.

3.4.3 The incentive profile

Once the net present value of the incentive for the TSO(s) is determined, the regulator would need to decide over which period and with which profile such an incentive would be paid.

As this is a regulatory amount, the spread of the incentive over time should plausibly be carried out by using the WACC such that:

$$\sum_{t=1}^{T} \frac{I_t}{(1+WACC)^t} = NPV\ of\ the\ incentive$$

where:

- I_t is the incentive paid out in year t; and
- t = 1, …, T is the period of time over which the incentive is paid.

It is also possible to envisage that all the annual incentive payments are equal ($I_1 = I_2 = \ldots = I_T$).

Note that, despite the fact that any incentive profile which respects the above condition should, in theory, be financially equivalent for the TSO(s), one might expect that the latter prefers to receive the incentive sooner rather than later. This could also be a ‘good deal’ for grid users, if this means that:

- An incentive paid sooner has greater ‘value’ for the TSO(s), which might lead to greater effort in identifying more efficient, innovative solutions with lower costs; and
- the cost of the incentive for grid users is reduced, as the time preference for them is not as strong as for the TSO(s).

On the other hand, there might be an advantage in spreading the payment of the incentive over more years in the sense that, in this way, the regulator would be better placed to assess the performance of the more efficient, innovative solution before the incentive is fully paid out.

3.5 Challenges with the implementation of the proposed scheme

The implementation of the proposed scheme also involves challenges related to:

- The need to identify the system need(s);
- The need to identify a traditional standard solution to the identified system need(s);
- The need to assess and validate the more efficient, innovative solution proposed by the TSO(s) and its costs;
- The way in which uncertainty about the future costs of the more efficient, innovative solution is taken into account in the proposed scheme.

In what follows we discuss these challenges and contend that they are not much different from those regulators face while implementing most of the typical regulatory schemes.

3.5.1 Identifying the system need(s)

One concerns often raised with regard to the proposed scheme refers to the complexity of identifying the system needs and the process for such an identification. This is clearly a complex task, but it is an inevitable first step in any system development planning exercise. In fact, it is difficult to imagine such a planning not being aimed at addressing specific system needs, which requires their identification.

Strictly speaking, there is an element of circularity in the identification of system needs and the planning of the actions to address such needs. In fact, the definition of the need(s) depends, to an extent, on the costs involved in addressing them. A simple example could better illustrate this point.

Consider a situation in which the interconnection capacity between two market zones is considered to be insufficient. This would be the case if the value of expanding such a capacity is higher than the expected costs of such an expansion. In theory, and leaving aside for the moment any issue related to uncertainty and the typical lumpiness of investments in transmission assets, the expansion should be planned up to the point where the marginal value of additional cross-border capacity equals the cost of developing an extra unit of capacity.

Therefore, the definition of the system need(s) in this case, in terms of the additional cross-border capacity which is optimal to develop, depends on the incremental cost of capacity. To the extent that more efficient, innovative solutions to increase cross-border capacity might be able to deliver the additional capacity at lower costs than the traditional standard solution, the optimal level of cross-border capacity might increase.

This circularity is, to an extent, common to most planning approaches based on cost-benefit analysis and therefore it is neglected at this stage of the assessment of the implementation challenges specific to the proposed incentive scheme.

3.5.2 Identifying a traditional standard solution to a specific system need or set of needs

The identification of the traditional standard solution to address specific system need(s) could be another demanding and difficult task and not all regulators in the EU might be properly equipped to perform it. However, reference to the way in which similar needs were addressed in the past could be used to determine the standard way of addressing each need or set of needs. Likewise, network planning might be used as a reference. TSOs may also assist regulators in such an identification, even though they might have an incentive to propose costlier solutions as a reference.

The allowed costs associated with such a standard way of addressing each of the needs or sets of needs might also be estimated on the basis of past experience. Moreover, standard unit costs for individual infrastructure assets and a 'calculator' for energy infrastructure unit investment costs provided by ACER[22] could also be used for this purpose.

3.5.3 Assessing and validating the more efficient, innovative solution proposed by the TSO(s) and its costs

More efficient, innovative solutions to address system needs are, by definition, new and little or no experience might be available regarding their technical characteristics, performance and costs, especially if deployed at scale. It is however to be stressed that the more efficient, innovative solutions which the proposed regulatory scheme aims at incentivising are those which are no longer at the research and development stage, but are instead ready to be deployed, even though they might not yet be frequently adopted. In fact, the incentive would not be paid if the chosen solution ended up not addressing the identified need(s) to the extent expected. In this sense, TSOs will be incentivised to propose solutions which have already reached a sufficient development stage[23].

Regulators would be faced by proposals from TSO(s) regarding such more efficient, innovative solutions and the related costs which they would have to endorse. This could be indeed a challenging task for regulators, which might require some specialised technical capability, which not all regulators might have. However, the auditing of the costs of such more efficient, innovative solutions and the benchmarking of such solutions proposed by TSOs in different jurisdictions might assist in the assessment and endorsement of the more efficient, innovative solution proposed by the TSO(s) and of the related costs.

3.5.4 Dealing with uncertainty

A final concern might relate to the way in which the proposed scheme would take uncertainty regarding future costs into account. Here it is useful to distinguish between cost overruns – or underspending – which are due to external factors and those which could have been under the control of the TSO(s). In the first case, adjustment mechanisms might be envisaged, as it is often the case with other incentive-based

[22] In June 2023, ACER published a Report on Unit Cost Indicators and an "Energy Infrastructure unit investment cost calculator", available at: https://www.acer.europa.eu/electricity/infrastructure/network-development/transmission-infrastructure-reference-costs.

[23] Solutions with still an uncertain performance should be promoted with other schemes, such as the pass-through of costs for research and development activities.

regulatory schemes. Instead, in the case of cost overruns imputable to the TSO(s), they would not be mitigated within the proposed scheme, but would be left to be absorbed by the TSO(s) – in the same way as cost underspending would be left to the TSO(s) to benefit from.

4 Task 1: Mapping existing incentive schemes and evaluating their effectiveness in terms of wide-scale deployment of cost-efficient alternatives to classical infrastructure solutions

As required by the Terms of Reference, Task 1 has been structured in three separate activities:

a) Mapping existing infrastructure efficiency-related incentives in EU Member States, Great Britain, Northern Ireland, Iceland and Norway. This mapping has been based on a desk review of the latest (2023) Report of the Council of European Energy Regulators (CEER) on Regulatory Frameworks for European Energy Networks[24], as well as on ACER's Report of June 2023[25];
b) Describing existing infrastructure efficiency-related incentives implemented in two extra-European jurisdictions, namely the United States and Australia;
c) Assessing the effectiveness of the implemented incentives in terms of their contribution to a higher utilisation of network infrastructure in jurisdictions that implement infrastructure efficiency-related incentives. In particular, we have looked for factual evidence of the effectiveness of these regulatory regimes when it comes to wide-scale deployment of such solutions.

Before presenting the results reached by our assessment, it is to be highlighted that infrastructure efficiency-related incentives are still not widely used by regulators, in Europe and elsewhere.

In several jurisdictions considered in this assignment, CAPEX is still regulated on a 'rate-of-return' or 'cost-plus' basis. Where incentives are provided, they aim at promoting investment cost efficiency, in the sense of rewarding cost savings with respect to the budgeted or standard costs, and with respect to a 'conventional' set of technologies. As the results of our assessment show, only in a very few cases, TSOs are explicitly incentivised to look for new, innovative and more efficient solutions to system needs.

Therefore, beyond a mapping of the different jurisdictions based on available documentation, we focus and discuss in more detail those limited cases in which innovation in addressing system needs is more explicitly promoted.

We focus on the regulatory treatment of certain activities of electricity transmission (and system) operators. However, we do not intend to provide a full assessment of how such activities are or should be regulated, but rather to focus more narrowly on the promotion of innovation in such activities.

The rest of this section is structured as follows:

- Section 4.1 provides a taxonomy of network regulation that facilitates a common understanding of the results of the mapping exercise;
- Section4.2 maps the current regulatory landscape for electricity transmission in Europe and highlights a few general trends;
- Section 4.3 narrows the focus to the incentive schemes adopted or currently discussed in five jurisdictions: Portugal, Italy, Great Britain, United States, and Australia;
- Section 4.4 presents data about the performance of the incentive schemes put in place in Italy, Great Britain and Australia to promote efficiency in addressing electricity system needs at the transmission level.

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[24] CEER (2023), *Report on Regulatory Frameworks for European Energy Networks 2022*, January, available at: https://www.ceer.eu/documents/104400/-/-/2a8f3739-f371-b84f-639e-697903e54acb.

[25] ACER (2023b), *Report on Investment Evaluation, Risk Assessment and Regulatory Incentives for Energy Network Projects*, June, available at: https://acer.europa.eu/sites/default/files/documents/Publications/ACER_Report_Risks_Incentives.pdf.

4.1 A taxonomy of network regulation

In this section, we present a brief classification of approaches to regulate transmission activities. We do not pretend to provide an exhaustive review and characterisation of all the approaches proposed or used for transmission regulation. This is not our objective. Our focus is on those approaches which can promote efficiency in network infrastructure investments.

At a preliminary level, it is to be emphasised that any infrastructure investment has to address a system need or a set of needs, such as supporting the functioning of electricity markets, the integration of new renewable energies or a higher level of service reliability. That is, the investment should respond to a purpose, and should not be planned and developed unless there is a need of the system to be addressed. As already highlighted in Section 3.1, this is a basic principle and refers to the typical regulatory requirement that any investment – or in fact any process of a regulated entity which is paid through the regulatory framework – should deliver benefits[26] and it should only be undertaken if such benefits exceed its costs. And the benefits derive from addressing system needs.

In this respect, at a conceptual level, efficiency in network infrastructure investment might refer to:

- reducing the costs of addressing the identified system needs through 'incremental' efficiency improvements, but without a significant departure from the traditional technological approach (e.g., savings on the acquisition or construction costs for new network elements, or savings in the financing of investments); and
- reducing the cost of addressing the identified system needs by introducing innovative, 'breakthrough' solutions which represent a significant departure from the traditional technological approach.

In reality, most incentive-based mechanisms do not differentiate between these two types of efficiencies, and there is a continuum of approaches aimed at dealing with different degrees of innovation in the way in which system needs are addressed.

Until recently, this did not represent a major issue, as electricity transmission was a sector mostly characterised by incremental innovation. However, in the past decade or so, technological advances and progress in digitalisation have allowed the implementation of innovative, 'smart' solutions to system needs. This development provides new relevance to the above-mentioned distinction.

As this analysis focuses on network investment, our starting point is the way in which CAPEX in electricity transmission is regulated.

In this respect, networks, at least for what concerns CAPEX, have been traditionally regulated according to the 'rate of return' approach. According to this approach, new assets are added to the 'regulatory asset base' (RAB), which is then remunerated by including, in the allowed revenues for the regulated entity, a CAPEX component, itself containing a 'depreciation' element (return of capital) and a 'capital remuneration' element (return on capital). Such an approach provides limited efficiency incentives to the regulated entities, mainly in two areas:

- in the cost of the investment, to the extent that the value of the new asset to be included in the RAB is approved *ex-ante* and is not based on actual costs. If this is the case, a network company able to develop the investment at a lower cost could keep the savings, and this is the incentive for acquisition/construction cost efficiency;

[26] In this context, benefits should be intended in the widest possible meaning, including not only monetisable benefits, but also non-monetisable ones, and those whose quantification might be complex. The difficulty of measuring benefits should not distract from the general regulatory test of positive net benefits for new processes or investments, whose (prudently incurred and efficient) costs are allowed for recovery through the regulatory framework.

- in the financing costs, to the extent that the financial structure of the investment (the equity-debt ratio) or of the regulated business as a whole is predefined and is not adjusted to reflect the actual structure of the regulated business, and the rates of return for equity and debt are predefined. If this is the case, a network company managing to obtain better financing conditions could keep the savings, and this represents the incentive for financing cost efficiency.

However, experience with the traditional rate-of-return approach to regulation suggests that the savings achieved by the regulated entity in those two areas are rarely passed on to consumers by a reduction of the CAPEX component of the allowed revenues. In fact, the above-mentioned assumptions at the basis of the considered incentives rest exactly on the fact that savings are not passed on to consumers, at least within the regulatory period.

Beyond this traditional approach, other mechanisms have been used to incentivise efficiency in expenditure and, more recently, in addressing system needs and therefore promoting the most efficient way of addressing these needs. In fact, advances in technologies and digitalisation are now allowing some system needs to be addressed by improving system operation procedures (which might involve an increase in operation and maintenance costs – OPEX), rather than only by an expansion of the network infrastructure (which would likely involve an increase in CAPEX).

These mechanisms include:

- Input-based incentive mechanisms, such as a revenue cap and its variant, the price cap. As the cost of networks does not generally depend on electricity volumes transported on them, a revenue cap seems a better-suited approach than a price cap.
- Output-based incentive mechanisms, also known as performance-based incentives. These mechanisms link the level of (part of) the allowed revenue to the attainment of predefined performance levels, with reference, for example, to the available capacity in a certain part of the network (e.g., interconnectors).

Both these mechanisms could promote the search for more innovative solutions to system needs, if these result in lower costs. A major challenge in this respect has been the fact that the way in which networks have been regulated treats OPEX separately and sometimes differently from CAPEX, with the former typically characterised by stronger efficiency incentives. This has led network companies to prefer CAPEX-heavy solutions, on whose costs they can earn a guaranteed return, and, if the return is paid on the basis of the actual investment costs, to have little incentives for investment efficiency (the CAPEX bias). To overcome this phenomenon, the TOTEX approach has been proposed.

However, in most instances, the revenue cap, on CAPEX or TOTEX, refers to the cost related to a reference technology scenario to address system needs. Moreover, it is not clear whether, within a TOTEX approach, regulators would accept the adoption of a totally different, more efficient, innovative, but much cheaper solution to the identified system needs without revising the cost benchmark, unless this is explicitly envisaged in the incentive scheme.

Other forms of what is traditionally defined as output-based regulation are also possible, with premia and penalties linked to the achievement, overachievement or underachievement of some predefined performance standards.

Therefore, for the purpose of the characterisation of the regulatory treatment of investment in energy networks, the following five categories will be used:

- Rate-of-return regulation applied to CAPEX,
- Revenue/price-cap regulation applied to CAPEX (and OPEX separately),
- Revenue/price-cap regulation applied to TOTEX, possibly maintaining a fixed CAPEX-OPEX structure,
- Performance-based regulation with explicitly defined performance targets,

- Regulation explicitly promoting innovation in addressing system needs (including benefit-based regulation).

With respect to this last category, it is to be emphasised that it is not uncommon for regulators to allow regulated companies some revenues to cover the cost of research and development of innovative technologies. This is a form of input-based regulation which has been widely applied for many years and focus on technologies at an early stage of development, usually well before they are ready to be deployed at scale[27]. At that point, these technologies (and the related processes) should become part of the tools available to the network operators to achieve higher levels of efficiency in addressing system needs. This latter situation, not the former, is the focus of the scheme proposed in this Report.

4.2 Mapping existing infrastructure efficiency-related incentives

In this section we present our results of a mapping of regulatory approaches implemented in the EU Member States, the United Kingdom, Iceland and Norway, using, to the extent possible, the characterisation presented in the previous section. Our interest is the extent to which incentive-based regulation is used in regulating electricity networks and the way in which it promotes innovation in addressing system needs.

Table 1 presents our characterisation of the regulatory framework applicable to OPEX and CAPEX in the countries under consideration. It is to be emphasised that this characterisation is sometimes subjective, as the regulatory frameworks in place in some countries might have features with different incentivising characteristics.

The information is mainly derived from the reports from CEER and ACER[28], where more details can be found.

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27 The interested reader may consider Bauknecht D. (2011), 'Incentive regulation and network innovation', *EUI Working Papers*, RSCASC 2011/02; Poudineh R., D. Peng and S. R. Mirnezami (2020), 'Innovation in regulated electricity networks: incentivizing tasks with highly uncertain outcomes', *Competition and Regulation of Network Industries*, 21 (2), 166-192; and Jamasb T., M. Llorca, L. Meeus and T. Schittekatte (2023), 'Energy network innovation for green transition: economic issues and regulatory options', *Economics of Energy and Environmental Policy*, 12 (1), 81-95.

28 The two reports are CEER (2023), *op. cit*., and ACER (2023b), *op. cit.*

Table 1: Mapping of existing infrastructure efficiency-related incentives in Europe applied to transmission.

Country	Regulatory approach to OPEX	Regulatory approach to CAPEX	Performance-based incentives (PBI) Benefit-based incentives (BBI)
AT	Cost-plus	Cost-plus	PBI: WACC adder to promote investments in the TYNDP[29]
BE	Revenue cap	Rate of return	PBI: on asset availability
BG	Rate of return	Rate of return	
HR	Cost-plus	Cost-plus	
CY	Revenue cap	Revenue cap	
CZ	Rate of return[30]	Revenue cap	
DK	Cost-plus[31]	Cost-plus[32]	
EE[33]	Rate of return	Rate of return	
FI	Revenue cap	Revenue cap	
FR	Revenue cap	Cost-plus (for investments in 'network' projects) Revenue Cap (for investments in 'non-network' projects: information systems and real estate).	
DE	Revenue cap	Revenue cap	
GB	Revenue cap (on TOTEX)		
GR	Revenue cap	Cost plus	
HU	Price cap	Price cap	
IE	Revenue cap	Rate of return	PBI: on investment planning and delivery, project delivery (for

29 Investments made according to the ten-year network development plan (TYNDP) need to be approved by E-Control. Resulting capital costs are recognised *ex-ante*. To promote and facilitate investments, an equity premium of 0.8% applies (which translates into an overall WACC of 5.20% p.a. for new assets).

30 CEER (2023) reports "incentive regulation/revenue cap" at p. 34. On the other hand, ACER (2023b) reports "rate of return with incentive-based regulation elements built in it" at p. 31.

31 CEER (2023) reports "*strict cost plus*" at p. 39. On the other hand, ACER (2023b) reports "*revenue cap*" on p. 31.

32 See previous footnote.

33 Estonia formally implements a revenue cap approach to both OPEX and CAPEX. However, as the regulatory period is not defined, the approach effectively amounts to rate-of-return regulation.

			transmission asset owners), for RES integration
IS	Revenue cap	Revenue cap	
IT[34]	Price cap	Cost-plus/rate of return	BBI: for increases of cross-zonal transmission capacity, for investment cost efficiency, for quality of supply (energy not supplied)
LV	Revenue cap	Revenue cap	
LT	Price cap	Price cap	
LU	Revenue cap	Revenue cap	
NL	Revenue cap	Revenue cap	
NI	Revenue cap	Revenue cap	
NO	Revenue cap	Revenue cap	
PL	Cost plus	Rate of return	
PT	Revenue cap (on TOTEX)		PBI: to improve technical performance of the network
RO	Revenue cap	Revenue cap	
SK	Price cap	Revenue cap	BBI: WACC adder for innovative investments
SI	Revenue cap	Revenue cap	PBI: some transmission investment linked to key performance indicators, voltage quality BBI: for smart grids
ES	Rate of return	Rate of return	
SE	Revenue cap	Revenue cap	

The mapping of existing incentives in Europe suggests that:

- incentive-based regulation, while being frequently used for electricity transmission networks, is still predominantly of a traditional form, with the ‘revenue-cap’ approach being the most common so far;
- in the large majority of the jurisdictions considered, the approaches to regulating CAPEX and OPEX are now somewhat aligned (i.e., a revenue cap is applied to both CAPEX and OPEX, albeit separately). This reduces the CAPEX bias in the regulatory approach. However, a TOTEX-based

34 Italy has started introducing TOTEX-based regulation for electricity transmission in 2024.

framework able to ensure a totally symmetric and consistent treatment of CAPEX and OPEX is currently implemented only in a few countries, such as Great Britain and Portugal.

In its typical application, followed in almost all jurisdictions, the revenue-cap approach is implemented with reference to budgeted or forecasted costs, including investments. Therefore, the reference network technology scenario is predefined and the efficiency incentives operate on the cost of the investments according to such a scenario. While some cost-saving innovation with respect to a constant technology is still possible, it is far from clear that the revenue cap approach applied in this way is envisaged by regulators to provide incentives for innovation which significantly modify the way in which system needs are addressed, for example from capital-intensive solutions to solutions mostly based on changes in processes or procedures (here the most obvious example is the use of dynamic line rating – DLR – as an alternative to investment in additional physical capacity). In this case, regulators might be tempted to reset, at the earliest opportunity, the reference cost basis to calculate the allowed revenues, since the regulatory parameters characterising the revenue cap are typically not calibrated to deal with significant technology shifts[35].

As already indicated, the TOTEX approach is aimed at addressing the CAPEX bias, even though, as shown in Table 1 above, most jurisdictions already apply the same approach to OPEX and CAPEX (most frequently a revenue cap applied to both), thus limiting the incentives for network operators to prefer CAPEX-heavy solutions to address system needs[36]. However, the main drawback of TOTEX is that it does not explicitly consider the possibility for network companies to opt for non-traditional, more efficient and innovative solutions. The cost savings which TOTEX aims at promoting are mostly those in the implementation of a given solution or set of solutions.

Some performance-based schemes have aimed at promoting innovation. Beyond those, no general output-based incentive scheme has so far been implemented or even explicitly proposed to promote the significant innovation in addressing system needs that the advances in technologies and digitalisation now make available.

In Europe, at the moment, as shown above, ERSE, the Portuguese regulator, and Ofgem, the British regulator, are implementing a TOTEX-based revenue-cap approach, the latter in the context of the RIIO[37] framework. The Italian regulator – ARERA – is starting gradually to implement it. The same regulator has been experimenting with other types of incentive regulation over the past years.

Beyond Europe, we have reviewed the experience in two federal jurisdictions: the USA and Australia. In the latter, the federal regulator – AER – has been providing incentives for innovative solutions for almost twenty years, while, in the USA, the federal regulator – FERC – after an attempt to introduce incentives for the deployment of 'grid enhancing technologies', has eventually opted for mandating the adoption of some of them.

In what follows we focus on the frameworks in place in Portugal, Italy, Great Britain, the USA and Australia. In section 5 we assess to what extent some regulatory approaches currently being implemented specifically promote innovation in addressing transmission system needs.

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35 In the most traditional application of the revenue-cap approach, cost savings obtained by the regulated companies are left with them until the end of the regulatory period. If the use of breakthrough technologies leads to disproportionate savings, this may put into question the accepted rationale of revenue-cap regulation.

36 However, network operators may still prefer more expensive solutions which would result in higher allowed revenues, including the remunation of the larger invested capital.

37 RIIO stands for Revenue=Incentives+Innovation+Outputs. See Section 4.3.3 for more on this.

4.3 A focus on jurisdictions implementing a TOTEX-based framework or specific incentives for innovation

In this section we provide further details of incentive regulation in the EU jurisdictions where regulators have been more active in pursuing efficiency in addressing electricity system needs by transmission system operators, as well as in the USA and Australia.

4.3.1 Portugal

The Portuguese energy regulator (ERSE) has been providing the transmission system operator, REN, with economic incentives since the reform of the electricity sector in 1999[38]. These incentives were initially targeted to achieve efficiency improvements in operational costs and took the form of a price or a revenue cap on OPEX, while CAPEX was subject to a cost-plus approach. This regulatory framework was then complemented by a series of additional incentives targeting not only quality of service, but also efficiency in investment. The latter were mostly designed to achieve incremental efficiency and contain the cost increases associated with a plan to expand the Portuguese transmission network significantly and integrate growing amounts of renewable energy sources[39].

Consistent with this goal was the incentive for the maintenance of end-of-life equipment, that REN received between 2014 and 2017 and that fostered the extension of the useful life of transmission assets, basically postponing their replacement[40]. In the subsequent regulatory period, covering 2018-2021, ERSE discontinued the incentive for the maintenance of end-of-life equipment and introduced an incentive to increase the economic efficiency of investments, through the use of reference prices in the valuation of the new equipment to be integrated into the network, and an incentive to rationalise costs.

The last regulatory period, which started in 2022, saw a profound reform, with ERSE replacing the previous regime with a revenue cap on TOTEX. The change was motivated by various reasons, including the need to: a) streamline the tariff-setting process, partially decoupling it from the approval of the Network Development Plan (NDP) by the Government, b) reduce the administrative burden and provide further flexibility to the regulator, and c) 'future-proof' the regulatory framework by introducing an important element of technological neutrality that would become essential in the context of the energy transition.

ERSE adopted a building-block approach to calculate the cost base for TOTEX, which includes an OPEX component and a CAPEX component[41]. At the beginning of the subsequent regulatory period, ERSE is expected to recalculate the regulatory asset base (RAB), considering the actual investment costs borne by the TSO, including possible overruns, and any possible amendment to the NDP.

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[38] Information presented in this section is mostly derived from a presentation delivered by ERSE during an ACER workshop for NRAs held in Athens on 23-24 October 2023. Additional sources are CEER (2023), *op. cit.*, and ACER (2023b), *op. cit*.

[39] The length of the transmission network increased by 600 km, roughly 7%, between 2014 and 2020. The interconnection capacity with Spain increased as well in that period. For an overview of the Portuguese electricity system, see IEA (2021), *Portugal Energy Policy Review*, June, available at: https://www.iea.org/reports/portugal-2021.

[40] Further information on this specific incentive scheme can be found in DNV (2023), *Study on the regulation of electricity and gas system operators, A study for the Netherlands Authority of Consumers and Markets*, April, available at: https://www.acm.nl/system/files/documents/onderzoek-buitenlandse-reguleringsmethodes-netbeheerders.pdf.

[41] The OPEX component is computed using a backward-looking method, i.e., considering the actual, audited operational cost of the TSO in the previous two years, while the CAPEX component is computed using a forward-looking method, i.e., considering the expected expenses associated with the NDP. Efficiency factors are then applied to these two components, also on the basis of the results of international benchmarking studies. Investments performed before 2022 and a few other costs are exempted from the application of those efficiency factors. Twenty-five per cent of the components subject to the efficiency factors are considered variable and indexed to some cost drivers, namely the total network length and the capacity of the producers connected to the network. In order to ensure financial neutrality, the rate of return assumed in the calculation of the allowed revenues is partially indexed to the evolution of the yields of the Portuguese 10-year treasury bonds, thus internalising the country's financial conditions.

In designing the new regime, ERSE has taken into consideration the concerns expressed by the network companies regarding the risks associated with the move to such a different regulatory model. This consideration justifies the introduction of a profit/loss sharing mechanism that minimises the risk of excessive deviations from a baseline return for the regulated company. The mechanism aims to protect both the regulated company and the consumers, and kicks in when the deviation from the baseline return exceeds a threshold. Initially, the sharing is on a 50-50% basis; however, when the deviation becomes larger than a certain level, the TSO shares all the profits and losses with the consumers.

Next to the TOTEX regime, ERSE introduced an incentive for the TSO to improve the technical performance of the network (IMDT). This incentive replaces the previously mentioned incentive schemes and adds a premium or a penalty on the TSO allowed revenues, depending on the achievement of some reference values that measure the technical performance of the network. Three indicators are used for calculating such a performance: the availability of equipment (with a 25% weight), the quality of service (25%) and the cross-border capacity made available to the day-ahead market (50%). In 2022, the incentive paid to REN was equal to 20 million euros, while the allowed revenues linked to the TOTEX regime totalled 271 million euros and other costs recognised by the regulator were equal to 15 million euros.

Although an assessment of the new regime is premature due to its recent implementation, ERSE suggests that some elements of the scheme will have to be fine-tuned and adjusted. These include: a) how to deal with extreme and unpredictable events, b) how to limit inflated business plans, and c) how best to take into account the evolution over time of the NDP.

4.3.2 Italy

The Italian energy regulatory authority (ARERA, previously named AEEG and AEEGSI) has a long tradition of providing the Italian transmission system operator, Terna, with incentives to ensure it operates and develops the transmission network efficiently and affordably for network users. After a first regulatory period (2000-2003) where the transmission service was subject to a price cap, the need to strengthen the network by accelerating the rate of investment in new physical capacity led to the adoption, consistent with a new legal mandate, of a differentiated regime for OPEX and CAPEX: the former remained under a four-year price cap, while the latter became subject to a rate-of-return regulation[42].

Over time, the Italian regulator complemented this basic regulatory framework in two ways. First, it introduced a series of output-based incentive mechanisms to ensure that the transmission system operator did not reduce costs at the expense of the service quality delivered to network users. Targets on the energy not supplied at the level of the primary stations and a remuneration, to be paid by the transmission system operator, of the mitigation service provided by distribution system operators (DSOs) during outages of the transmission system were introduced in 2007, contributing to significant improvements in continuity of supply. Second, the Italian regulator introduced in 2004 an extra remuneration of the capital spent on specific projects, particularly relevant to the system. This incentive mechanism enabled the regulator to direct the attention of the transmission system operator towards projects able to reduce congestion between market zones or increase the net transfer capacity at the borders; it also facilitated the deployment of storage systems in the context of pilot projects[43].

[42] An overview of the Italian regulatory framework for electricity networks during the first decade after the restructuring of the sector can be found in Polo, M., G. Cervigni, F. M. D'Arcangelo and F. Pontoni (2014), La regolazione delle reti elettriche in Italia, *IEFE Research Report*, n. 15, June, available at: https://green.unibocconi.eu/sites/default/files/media/attach/RR-15.pdf.

[43] The mechanism offering the extra remuneration of invested capital was phased out in 2016. For an assessment of the experience with this mechanism and a similar one in the US, consider Keyaerts and Meeus (2017), 'The regulatory experience of Italy and the United States with dedicated incentives for strategic electricity transmission investment', *Utilities Policy*, 46, 71-80.

However, the extra remuneration for specific projects, while prioritising and accelerating their development, provided little incentives to seek more efficient, innovative, less CAPEX-intensive solutions. Therefore, in 2015, ARERA decided gradually to move away from input-based incentive regulation and adopted a new regulatory framework, rewarding the transmission system operator on the basis of the expected benefits deriving from individual investment decisions[44]. The shift to a new regulatory regime – the so-called '*Regolazione per Obiettivi di Spesa e di Servizio'* (Regulation through Expenditure and Service Targets – ROSS) – aims to ensure the selective development and efficient use of infrastructure in the context of the energy transition. It is expected to be introduced in two steps and be completed in the coming years. In the first step, the so-called 'ROSS-base', CAPEX and OPEX start to be treated together and the allowed revenues of the transmission system operator are based on total expenditure (TOTEX approach). More specifically, starting from 2024, new expenditures will be shared according to CAPEX and OPEX rates to be set by ARERA on the basis of both CAPEX/OPEX historical shares and forward-looking estimates, instead of using actual values of CAPEX and OPEX. In the second step, the so-called 'ROSS-integrale', a more advanced implementation of TOTEX regulation is expected to take place by implementing a methodology and a monitoring and reporting system that will give the possibility to the regulator to assess actual expenditures and outputs achievements by the TSO[45]. This step is foreseen to be introduced by 2026 (rules for this second implementation phase were under consultation in the second half of 2023).

In the transition to the new regime, ARERA has introduced, on an experimental basis, a few output-based incentive schemes targeting the electricity TSO with the aim of addressing specific system needs and promoting the adoption of innovative solutions.

The first of these mechanisms, introduced in 2018, rewards the increase of cross-zonal transfer capacity within Italy and at the borders with neighbouring transmission systems, up to a certain target capacity, proposed by the transmission system operator and approved by the regulator for each section of the network. The reward received by the transmission system operator is proportional to the increase in the cross-zonal transfer capacity and is received in full only if the target capacity is achieved. The reward level is calculated on the basis of two factors: the pre-existing congestion on the relevant section of the network (with an 80% weight) and the increase in socio-economic welfare associated with the expansion of the transfer capacity (20%). In this way, the benefits generated by the expansion of the transfer capacity are shared between the transmission system operator and network users. Based on the conventional assumptions that investments have a 25-year economic life, one annuity of the benefits is left to the transmission system operator as the incentive, while the network users benefit from the remaining 24 annuities[46]. The mechanism covered the period 2019-2023 and foresaw a maximum incentive equal to 150 million euros over the five years.

The second mechanism, introduced in 2019, is complementary to the previous one and rewards investment cost efficiency. If the CAPEX associated with a project ensuring the increase in cross-zonal transfer capacity is lower than a reference value defined by the regulator for the relevant section of the network, then the transmission system operator receives a reward that is commensurate with the incentive it gets for having

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[44] The information in this section are mostly taken from ARERA (2023b), Documento per la consultazione 474/2023/R/EEL, Orientamenti per la regolazione infrastrutturale del servizio di trasmissione dell'energia elettrica per il sesto periodo di regolazione 2024-2027, 17 ottobre, available at: https://www.arera.it/fileadmin/allegati/docs/23/474-23.pdf. Some of the relevant information is also available in English in Oxera (2021), Methodology review for a regulatory framework based on a total expenditure approach ('ROSS-base') – Prepared for Autorità di Regolazione per Energia Reti e Ambiente (ARERA), December, available at: https://www.arera.it/fileadmin/allegati/docs/21/615-21oxera.pdf.

[45] The new methodology will give more prominence to the forward-looking estimates of CAPEX and OPEX included in the investment plans submitted by the TSO to the regulator.

[46] The TSO is penalised via a claw-back mechanism in case it makes available to market actors, in the years following the awarding of the incentive, an amount of transport capacity lower that the conventional transport capacity communicated to the regulator.

increased the transfer capacity. As an example, if actual CAPEX is 50% of the reference CAPEX, then the transmission system operator gets an additional reward equal to 50% of that it receives due to the increase in cross-zonal transfer capacity. The mechanism covered the period 2020-2023 and implicitly foresaw a maximum incentive, as it could, in the best case, double the incentive paid for the increase in transfer capacity (i.e., in case of a 100% reduction of CAPEX).

4.3.3 Great Britain

The RIIO framework implemented in Great Britain over the last ten years is another example of a TOTEX-based incentive framework, which relies on business plans presented by the regulated companies[47]. Beyond the greater engagement of regulated companies with stakeholders to define the regulated companies' business plans, the main building blocks of RIIO are: a) the output of the networks[48], i.e. which system needs the network operator is aiming to address, which are then at the basis of the network operators' business plan, also presenting the revenue requirement over the length of the regulatory period; b) the stronger incentivising properties of the framework, by extending the regulatory period to eight years in its first implementation (2013 – 2021)[49]; c) the incentive and uncertainty mechanisms, which lead to adjustments in the allowed revenues during the regulatory period and are designed to improve both efficiency and standards of performance[50]; and d) specific innovation incentives, which were considered necessary, beyond the incentives already in the core mechanism, to encourage changes in behaviour and service by network companies as the energy system adapts to new technologies and decarbonisation. In particular, in the first implementation of the RIIO framework, there were three specific innovation mechanisms (together called Innovation Stimulus Package – ISP) which were designed to fund the investments for innovation. They were:

- the Network Innovation Allowance (NIA), which sets an allowance that each of the RIIO network companies receives to fund small-scale innovative projects and the preparation of submissions to the Network Innovation Competition;
- the Network Innovation Competition (NIC), which is an annual competition providing funding to a small number of larger and more complex innovation projects;
- the Innovation Roll-out Mechanism (IRM), which facilitates the rollout of innovative technologies, which is expected to bring long-term value for customers, carbon and/or environmental benefits.

In its second implementation (RIIO-2), from 2021 to 2026, a far greater number of uncertainty mechanisms were introduced where the scope of work was unclear when business plans were submitted. These are called volume drivers and trigger additional allowances based on the type of work and the output it delivers. There are a number of reopener windows for different investment areas, from sulphur hexafluoride emissions reduction to cyber security, and also mechanisms in place for agreeing costs for large onshore

47 For an overview of how the RIIO framework has emerged over time, look at Rious V. and N. Rossetto (2018), 'The British reference model', in L. Meeus and J.-M. Glachant (ed. by), *Electricity Network Regulation in the EU: The Challenges Ahead for Transmission and Distribution*, Edward Elgar Publishing: Cheltenham, UK, 3-27. For a description of the more recent developments of the RIIO framework look at DNV (2023), *op. cit*.

48 There are six output categories considered in RIIO: safety, environmental impact, customer satisfaction, social obligation, conditions for connections, reliability and availability.

49 However, Ofgem, the British regulator, reverted to a more common five-year regulatory period in the second implementation of the RIIO framework.

50 Both because of the length of the price-control period (8 years) and the extent of technology and market changes, the projected business plans are subject to a degree of uncertainty. Committing to a fixed revenue profile (net of incentive payments) over the period would create unnecessary risk for companies and/or users of the networks. To address this, a baseline revenue is established to which a range of adjustment or uncertainty mechanisms are applied to enable revenue changes during the period – for example, extra revenues for providing greater network capacity. They apply only where changes in cost or output/activity are outside the control of the regulated companies and have a material impact on the cost of operation.

transmission investment projects. RIIO-2 maintained the NIA, while replacing the NIC and the IRM with a Strategic Innovation Fund (SIF).

Therefore, when it comes to incentivising innovative solutions to address system needs, the RIIO approach combines the general incentivising properties of the revenue cap approach, which in this case applies to a business plan agreed with grid users, with specific innovation mechanisms to which network companies can apply in order to have the different stages of innovation funded.

4.3.4 United States

The use of incentive regulation for electricity transmission activities in the USA is relatively recent, as it was only in 2005 that the Federal Energy Regulatory Commission (FERC) was mandated, by an amendment of the Federal Power Act, to establish incentive-based rate treatments to promote capital investment in electric transmission infrastructure, which it did the following year. The original incentives included adders to the return on equity (ROE) and non-ROE financial incentives, such as a 100% recovery of construction work in progress (CWIP) and regulatory asset treatment of deferred costs.

However, it was only more recently, in 2019, that FERC launched a consultation on the deployment of grid-enhancing technologies (GETs)[51]. One of the questions put for consultation related to the possibility of introducing ‘shared savings’ as an incentive to promote the deployment of GETs. The proposal envisaged that a portion of the system-wide cost savings created by an investment in GETs would be shared, as an incentive, with the asset owner. It appears that this approach was initially proposed to FERC, among others, by a coalition of technology providers which were claiming that ROE-based incentives promote larger capital investments (the ‘CAPEX bias’).

During the consultation, several stakeholders, including independent system operators (ISOs), expressed concerns regarding the introduction of the ‘shared savings’ approach. It seems however that at least some of these concerns were directed not as much at the essence of the scheme, but rather at the way in which FERC intended to implement it. For example, ISOs objected to the role that they would have to play in the implementation of the scheme, by having to quantify the benefits of the deployment of GETs and the related incentives. They also mentioned that applying dynamic line ratings (DLRs) also on lines which are not congested would increase costs without much benefit for consumers.

As a result of the opposition to the proposed scheme that emerged during the consultation, FERC eventually decided to adopt a different approach. With Order No. 881 in December 2021, FERC required transmission providers, both inside and outside organised markets, to use ambient-adjusted ratings[52] as the basis for increasing the accuracy of near-term line ratings. While the Order does not mandate the adoption of dynamic line ratings – ratings that account for other factors like wind speed – the rule does require that organised market operators establish and maintain systems and procedures necessary to allow transmission owners that would like to use dynamic line ratings the ability to do so. The rule acknowledges that dynamic line ratings may deliver incremental benefits. As a result, in 2022 FERC launched two consultations:

- The first consultation was launched in February 2022, on whether dynamic line rating should be mandated further to increase the accuracy of USA transmission line ratings, on the trade-offs

[51] The technologies explicitly considered by FERC include, but are not limited to: a) power-flow control and transmission switching equipment; b) storage technologies; and c) advanced line rating management technologies.

[52] Ambient-adjusted ratings are only a subset of dynamic line ratings, as they only consider air temperature in determining the time profile of the capacity of a network element.

associated with the implementation of DLRs[53], and on whether it should establish specific criteria for identifying transmission lines that would benefit from the technology;

- The second consultation was launched in April 2022, on whether dynamic line rating shall be mandated as part of a broader long-range transmission planning and cost allocation approach by ISOs. In particular, FERC proposed to require that public utility transmission providers more fully consider two specific technologies in their regional transmission planning and cost allocation processes: dynamic line ratings and advanced power-flow control devices.

It seems therefore that, for the moment, FERC has abandoned the idea of promoting GETs through incentive-based regulation, such as 'shared savings', and might instead opt for an approach based on mandating the inclusion of GETs into the planning considerations of ISOs. It is clear that mandating the use of a specific technology is not equivalent to promoting its deployment by focussing on and incentivising the attainment of predefined performance targets (such as, for example, an expansion in the transmission capacity).

More details on the recent developments in the regulation of innovative solutions to system needs in the USA are provided in Annex I.

4.3.5 Australia

The Australian Energy Regulator (AER) has provided incentives to transmission network service providers (TNSPs) since its gradual take-over of the responsibilities of state regulators in the mid to late 2000s[54]. In particular, AER adopted a five-year revenue cap for OPEX and one for CAPEX, to induce TNSPs to spend network users' money prudently and efficiently. On top of this, AER gradually introduced additional incentive schemes with the aim of promoting specific behaviours by TNSPs, which further foster cost efficiency and generate value for network users.

The first two additional incentive schemes for transmission were introduced by AER already in 2007. They are the Efficiency Benefit Sharing Scheme (EBSS) and the Service Target Performance Incentive Scheme (STPIS). The EBSS allows a TNSP to retain any OPEX saving it has obtained in a given year, measured against a forecast made by AER on the basis of the OPEX reported by the same TNSP in the previous year. The introduction of the EBSS was justified by AER for two reasons. On the one hand, the EBSS provides the TNSP with an incentive to improve efficiency also in the years close to the end of a regulatory period and, on the other hand, the EBSS induces the TNSP to reveal to the regulator a more accurate estimate of what could be its efficient OPEX level. The STPIS, adopted in the same year as the EBSS, complements the EBSS by rewarding or penalising a TNSP for the quality of the transmission service it provides. The quality of the transmission service is measured in terms of system reliability (unplanned outages). TNSPs retain, for a period of five years, the value for network users of any improvement in the level of system reliability or pay

[53] A February 2021 study performed by consulting firm The Brattle Group estimated that DLRs, when implemented with other grid-enhancing technologies, could double renewable energy penetration in the wind-rich Southwest Power Pool region. See Tsuchida T. B., S. C. Ross and A. Bigelow (2021), *Unlocking the Queue with Grid-Enhancing Technologies. Case Study of the Southwest Power Pool*, Final Report – Public Version, 1 February 2021, available at: https://watt-transmission.org/wp-content/uploads/2021/02/Brattle__Unlocking-the-Queue-with-Grid-Enhancing-Technologies__Final-Report_Public-Version.pdf90.pdf. Another study, released in February 2022 by the USA Department of Energy, found that implementing DLRs on just 16 transmission line segments in New York would cut wholesale electricity costs in the state by $1.8 million annually and reduce renewable energy curtailment by 9%. See DOE (2022), *Grid-Enhancing Technologies: A Case Study on Ratepayer Impact*, February, available at: https://www.energy.gov/sites/default/files/2022-04/Grid%20Enhancing%20Technologies%20-%20A%20Case%20Study%20on%20Ratepayer%20Impact%20-%20February%202022%20CLEAN%20as%20of%20032322.pdf.

[54] The information contained in this section relies extensively on AER (2021), *Review of incentive schemes for networks – Discussion paper*, Commonwealth of Australia, December, available at: https://www.aer.gov.au/system/files/AER%20-%20Review%20of%20expenditure%20incentive%20schemes%20-%20discussion%20paper%20-%20%20December%202021.pdf.

the cost borne by network users due to a decline in system reliability. This incentive is expected to prevent TNSPs from reducing costs and possibly earn the rewards provided by the EBSS, merely by degrading the quality of the transmission service.

In 2014, a revision of the STPIS introduced a Network Capability Component, which incentivises TNSPs to undertake small, highly beneficial projects, characterised by short payback periods, that deliver improvements in the capability of the transmission network at times when it is most needed. To qualify for this component of the STPIS, TNSPs must submit a Network Capability Incentive Parameter Action Plan (NCIPAP), featuring the OPEX and low CAPEX projects that they aim to implement in order to improve the capability of one or more transmission network elements.

A third incentive scheme that comes on top of the revenue cap, the Capital Expenditure Sharing Scheme (CESS), was added by AER in 2013 and started to pay out in 2019[55]. This scheme follows a logic similar to that of the EBSS and allows TNSPs to retain 30% of the CAPEX efficiency gains achieved during a regulatory period (30:70 sharing ratio). Like in the case of the EBSS, the savings are measured against a forecast computed by AER on the basis of historical CAPEX over a multi-year period. CESS is expected to induce TNSPs to undertake efficient CAPEX and to ensure that only efficient CAPEX is added to the RAB, reducing the burden for network users and revealing the efficient CAPEX level of TNSPs to the regulator.

4.4 Assessment of the performance of some incentive-based regulatory schemes

In this section we present some data, made available by regulators, regarding the performance of some of the incentive schemes put in place to promote efficiency in addressing electricity system needs and illustrated in Section 4.3.

No assessment of the performance of incentive-based regulatory schemes has been conducted in Portugal and the USA. In the case of Portugal, the scheme is currently being implemented and therefore it is too early for an assessment of its performance to be meaningfully conducted. In the USA, as indicated in Section 4.3.4, FERC eventually decided to mandate the consideration of some GETs in network planning and therefore no incentive-based scheme was put in place.

4.4.1 Italy

According to the Italian regulator, the two output-based incentive schemes targeting the electricity transmission system operator and promoting the increase in cross-border capacity and investment cost efficiency, which were introduced in 2018 and 2019, respectively, were relatively successful as they have induced Terna to implement a number of CAPEX-light projects in 2020 and 2022, which have increased the transfer capacity in some sections of the transmission network by several hundreds of MWs. These projects, which mostly consisted in the deployment of specific protection schemes, including dedicated devices for the remote disconnection of renewable power plants, and dynamic line rating, were concluded in a matter of months. The costs borne by Terna for these projects were in the order of 5.5 million euros for the projects implemented in 2020 and 37 million euros for the projects implemented in 2022[56]. They generated benefits

[55] After CESS, AER has introduced other incentive schemes, which either address distribution networks or have not had, so far, a relevant impact due to their recent introduction. They are the Demand Management Incentive Scheme (DMIS) and the Customer Service Incentive Scheme (CSIS).

[56] Detailed numbers about the amount of the incentive paid and the costs borne by Terna can be found in ARERA (2022), Deliberazione 25 gennaio 2022, 23/2022/R/EEL, Determinazione del premio per la realizzazione di capacità di trasporto interzonale nell’anno 2020, available at: https://www.arera.it/fileadmin/allegati/docs/22/023-22.pdf, and ARERA (2023a), Deliberazione 17 ottobre 2023, 473/2023/R/EEL, Determinizione di premi per la realizzazione di capacità di trasporto interzonale e per l’efficienza degli investimenti relativi al servizio di trasmissione dell’energia elettrica, available at: https://www.arera.it/fileadmin/allegati/docs/23/473-23.pdf.

well above one billion euros, leading ARERA to award Terna 127.3 million euros as the incentive payment under the first scheme and 52.8 million euros as the incentive payment under the second scheme.

Due to the significant increase in transfer capacity achieved and the congestion that still affects the Italian network, ARERA is extending the two incentive mechanisms for 2024. It also aims to fine-tune them, introducing, for instance, an additional incentive linked to the timely delivery of the projects, which can increase or decrease the reward by up to 30%. Finally, ARERA is also considering the possibility of penalising the transmission system operator in case a project turns out to be more expensive than the reference CAPEX[57].

4.4.2 Great Britain

In 2021, the first implementation of the RIIO framework (RIIO-1) for electricity transmission came to an end and a new regulatory period started (RIIO-2). Early assessments of the results of RIIO-1 have somewhat downsized the revolutionary nature of the regulatory reform and highlighted the difficulties that have emerged in its implementation[58]. First, it is clear that the departure from the traditional input-based regulation was much smaller than anticipated. The vast majority of the revenues of the network companies are still linked to the remuneration of the capital invested on the basis of a rate of return defined by the regulator and an investment plan approved *ex-ante*. The total value of the output-based rewards still represents a small fraction of the overall revenues. Second, the adoption of multiple targets may have reduced global efficiency, as it has introduced multiple constraints in the equalisation of marginal costs and benefits. Third, the complexity of RIIO has not significantly reduced the information asymmetry which penalises the regulator, while diminishing the transparency of the regulatory framework and the possibility to learn important lessons and ensure incremental improvements of the regulatory framework itself over time. Separating the effects of the various schemes and taking into account all their interactions is a difficult and burdensome task. Moreover, the long duration of the regulatory period (eight years) has made any forecasting exercise by the regulator and the network companies themselves more difficult and uncertain, thereby increasing the risk of over- or under-incentivising the network companies. Finally, early assessments of RIIO-1 suggest that the outputs to be used to regulate network companies are difficult to evaluate precisely, especially in a highly dynamic context, and that regulated companies generally have easily achieved the targets, getting higher than expected returns.

In this respect, Ofgem, the British regulator, has been tracking the performance of the RIIO-1 regulatory framework in the first seven years, from 2013 to 2019, using a number of metrics related to the performance of transmission companies in Great Britain and the different output dimensions pursued by RIIO (see Section 4.3), including:

- The return on regulatory equity,
- Actual expenditure vs. allowed expenditure,
- Actual volumes of electricity not supplied vs target.

[57] Details about the position of ARERA on future developments were expressed first in ARERA (2023b), *op. cit*. A final decision on the matter was adopted in early 2024 and is described in articles 42 and 46 of Annex A to ARERA (2024), *Deliberazione 27 febbraio 2024 55/2024/r/eel, Approvazione della regolazione output-based del servizio di trasmissione dell'energia elettrica, per il periodo 2024-2027*, available at: https://www.arera.it/atti-e-provvedimenti/dettaglio/24/55-24.

[58] See Brunekreeft G., J. Kusznir, R. Meyer, M. Sawabe and T. Hattori (2020), 'Incentive regulation of electricity networks under large penetration of distributed energy resources – selected issues', *Bremen Energy Working Papers*, No. 33; Jamasb T. (2021), 'Incentive regulation of electricity and gas networks in the UK: from RIIO-1 to RIIO-2', *Economics of Energy & Environmental Policy*, 10 (2), 181-196. Particularly critical of the outcomes of the reform is Thomas S. (2023), 'A perspective on the RIIO formula: Old wine in new bottles', *Utilities Policy*, 80, 101450.

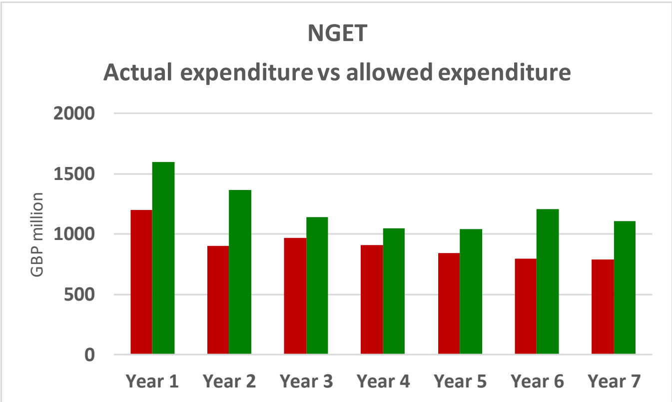
In what follows we present the results of this monitoring[59] for the three transmission companies operating in Great Britain: National Grid Electricity Transmission (NGET), excluding system operation costs; Scottish Hydro Electricity Transmission (SHET); and Scottish Power Transmission (SPT).

Ofgem reckons that, over the full RIIO-1 period (2013 – 2021), the three electricity transmission companies earned a return on equity of between 9.4% and 11.3%, as indicated in the following Table 2.

Table 2: Return on equity under RIIO-T1 experienced by British electricity transmission companies (source: Ofgem).

Electricity Transmission Company	Return on equity under RIIO-T1 (2013 – 2021)
National Grid Electricity Transmission	10.76%
Scottish Hydro Electricity Transmission	11.26%
Scottish Power Transmission	9.40%

These returns have to be compared with the rates of return on equity envisaged by Ofgem in its final proposal for electricity transmission under RIIO-1 of December 2012[60]. In that document, a baseline rate of return on equity of just above 7% was foreseen for all three electricity transmission companies, with potential additional income from incentives providing the opportunity to increase such a return to between 10% and 11% for SHET and SPT and to between 9.5% and 10% for NGET. As the monitoring results presented in the table indicate, all three electricity transmission companies managed to achieve returns on regulatory equity well in excess of the foreseen baseline level, and close to or even above the high end of the range foreseen by Ofgem. This was at least in part due to their ability to reduce costs below the allowed expenditure level in most of the years (and in all years for NGET), as presented in Figure 1 (red bars represent actual cost and green bars allowed expenditure).



59 See: https://www.ofgem.gov.uk/energy-data-and-research/data-portal/energy-network-indicators.

60 Ofgem (2012), *RIIO-T1: Final Proposals for National Grid Electricity Transmission and National Grid Gas*, 12 December, available at: https://www.ofgem.gov.uk/sites/default/files/docs/2012/12/4_riiot1_fp_finance_dec12.pdf.

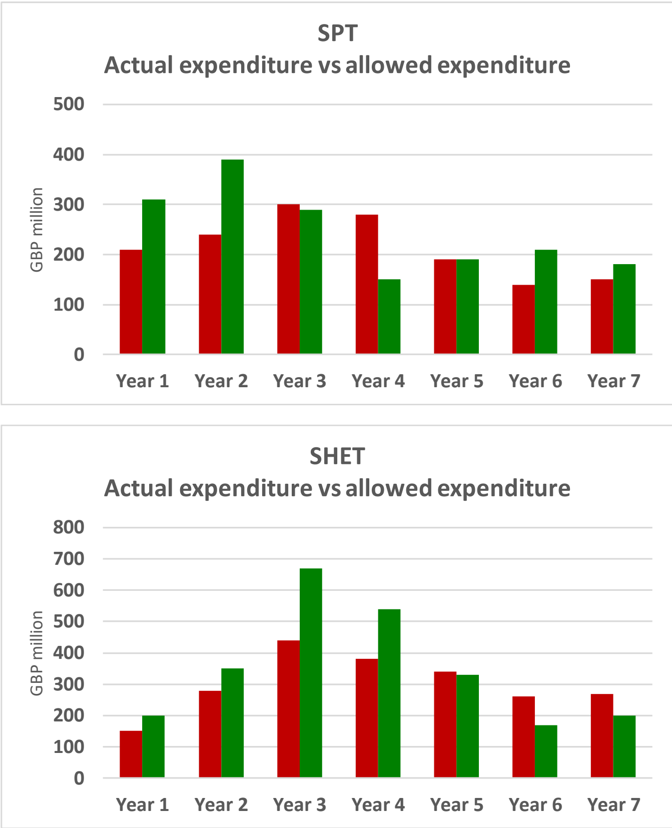
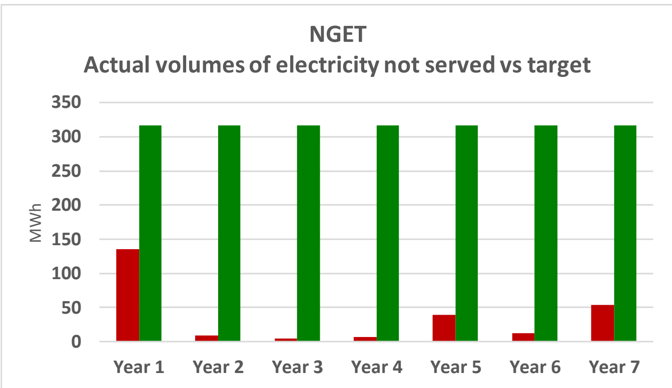


Figure 1: Comparison between actual and allowed expenditures for the three transmission companies operating in Great Britain during the first seven years of RIIO-1 (source: Ofgem).

Moreover, the three electricity transmission companies appear to have been able easily to overachieve the supply continuity target set by Ofgem, measured in terms of energy not served, as shown in Figure 2 (red bars represent actual volumes of electricity not served and green bars the target set by Ofgem).



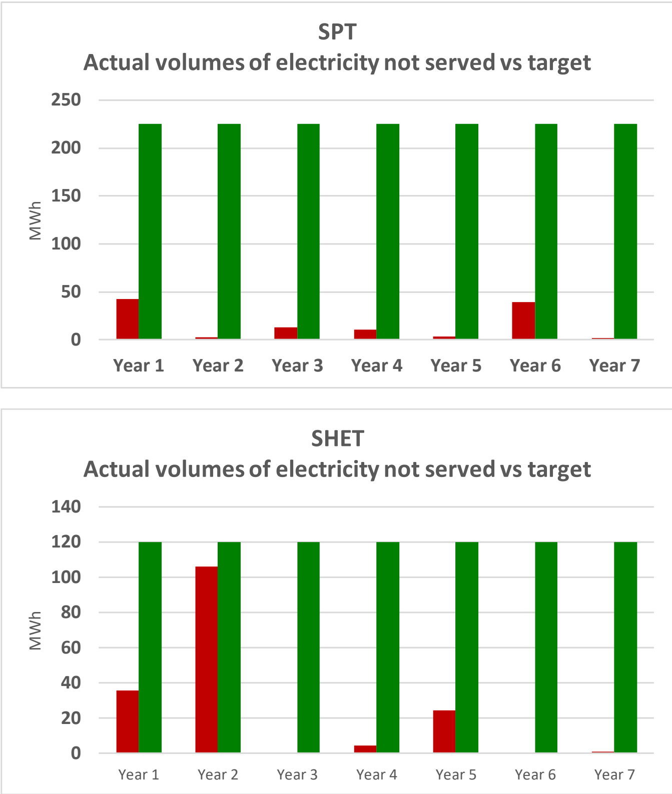


Figure 2: Comparison between actual volumes of electricity not served and the related target for the three transmission companies operating in Great Britain during the first seven years of RIIO-1 (source: Ofgem).

While not conclusive regarding the performance of the RIIO scheme, these results seem to confirm that such a scheme, in its first implementation, was fairly generous in its targets and that all three transmission companies in Great Britain responded to the incentives, reducing expenditures well below the allowed level, thus obtaining profitability levels well above the baseline levels foreseen by Ofgem when the scheme was introduced, while maintaining quality standards (in terms of electricity not serve) well above their respective targets.

As the RIIO scheme has an emphasis on responding to customers' needs, it is also interesting to see how transmission companies have engaged stakeholders. The Stakeholder Engagement Incentive encouraged regulated network companies to engage effectively with a wide range of stakeholders and use the outputs from that process to inform how they plan and run their businesses. Under this incentive, a network company may receive a financial reward depending on the quality of its stakeholder engagement. An independent panel of consumer and stakeholder engagement experts assessed performance with scores out of 10. Figure 3 presents the results of this assessment within RIIO-1. It shows a mixed record of stakeholder engagement for the three companies over the first implementation of RIIO.

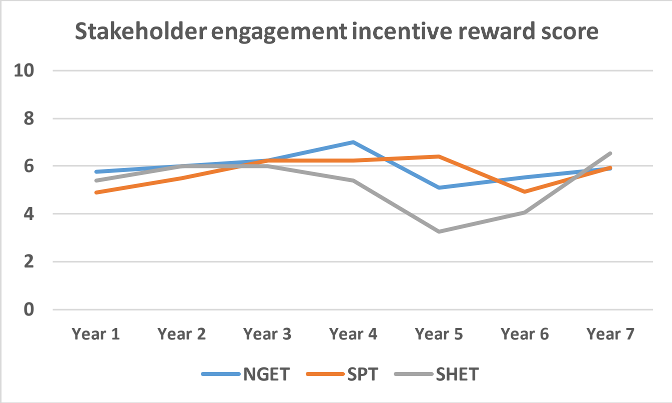


Figure 3: Assessment of the performance of the three transmission companies operating in Great Britain during the first seven years of RIIO-1 in terms of stakeholder engagement (source: Ofgem).

4.4.3 Australia

The Australian federal energy regulator, AER, has been generally satisfied with the incentive schemes that it has introduced over the years. Data reported by AER in its yearly Electricity Network Performance Report suggest that the implementation of the incentive schemes has coincided with a reversal of the significant growing trend of network costs that Australia observed for about a decade and which raised significant concerns among network users[61]. Since roughly 2015, network costs have almost constantly declined, both in absolute terms and per customer, while the reliability of the transmission service has improved and network productivity increased. Given the relatively small economic cost of the incentives – data for 2022 suggest that the TNSPs received 56 million Australian dollars due to the three incentive schemes mentioned in Section 4.3.5, out of a total revenue of around 2.5 billion Australian dollars[62] –, AER believes that those schemes provide value for money to network users[63].

While TSNPs have generally shared the view of the regulator, customer associations and communities have expressed a somewhat less positive opinion on the incentive schemes implemented by AER. In particular, they raised concerns about the transparency of the schemes and the possibility that network service providers be rewarded via the EBSS and the CESS not only due to genuine efficiency improvements, but also because of forecast errors, inability to obtain permits for the realisation of new infrastructures and deferral of projects to the following regulatory period. During various regulatory determinations they also questioned the limited use of benchmarking by the regulator.

AER reacted to these concerns by opening a review of the incentive schemes in late 2021, which was concluded in Spring 2023 with the adoption of a final decision[64]. Based on its assessment, AER decided to

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61 For a description of the Australian electricity network regulation see, among others, Simshauser P. (2021), ‘Lessons from Australia’s National Electricity Market 1998-2018: strengths and weaknesses of the reform experience’, in Glachant, Joskow and Pollitt (ed. by), *Handbook of Electricity Markets*, Edward Elgar Publishing, 242-286.

62 AER (2023b), *Electricity Network Performance Report*, Commonwealth of Australia, July, available at: https://www.aer.gov.au/publications/reports/performance/electricity-network-performance-report-2023.

63 Despite representing only 1-3% of total network revenues, the incentive schemes have a positive impact on the profitability of TNSPs, increasing the return on regulated equity by 0.4-0.9 percentage points.

64 AER (2023a), *Review of incentive schemes for networks – Final decision*, Commonwealth of Australia, April, available at: https://www.aer.gov.au/system/files/AER%20-%20Final%20decision%20-%20Review%20of%20incentive%20schemes%20for%20networks%20-%2028%20April%202023_1.pdf.

retain the EBSS as it was, while partially amending the CESS and planning a more targeted review of some elements of the STPIS for late 2023[65].

With regard to CESS, AER highlighted the difficulty in accurately estimating future CAPEX and the importance to improve constantly such forecasts to ensure that CESS provides appropriate incentives. In order to reduce the 'burden' on forecasts, AER mandated TNSPs to provide additional information to explain the reasons for the differences between the regulator's expenditure forecast and the actual expenditure. It also introduced a more sophisticated system for the recognition of capital cost savings (Bright-Line Tiered Test) that is expected to reduce the incentive for TNSPs to react strategically to the CESS. The original sharing ratio of 30:70 is then going to apply only for underspends up to 10 per cent of the forecast CAPEX and for any overspends, while a 20:80 sharing ratio will apply for underspends exceeding 10 per cent. Finally, the regulator decided to introduce more flexibility in the application of CESS to specific transmission contingent projects and to establish a separate CESS for contingent projects.

With regard to the STPIS, AER accepted the view expressed by TSNPs that some of its components, such as the Market Impact Component (MIC), which are based on historical data, may no longer be fit for purpose due to the massive uptake of renewable energy power plants, which have made congestion and reliability issues much more frequent in recent years and are to a limited extent under the control of network service providers. AER also recognised that the Network Capability Component (NCC), while successful in inducing TNSPs to explore non-network alternatives to expand transmission network capability, is administratively complex to apply, as it is based on a business case analysis and outcomes are generally considered project by project. This component is also likely to be less relevant than in the past due to the increasing collaboration of TNSPs and the Australian Energy Market Operator (AEMO) with regard to transmission network planning and the cost-benefit analysis of new projects. The results of the targeted review of some of the elements of the STPIS are expected in 2024[66].

From this overview, it seems that AER is keen to retain the inventive schemes it has introduced in the past, but is also aware of the constant need to refine and revise them to ensure that they adapt to the evolving context and preserve their incentive properties. The experience of Australia also suggests the importance of transparency and information availability, without which incentive schemes for more efficient investment may leave too much money on the network service providers' table and may cause a backlash by network users.

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[65] The targeted review of some elements of the STPIS started with the publication of an Issues Paper on 8 December 2023 and the opening of a public consultation. See: https://www.aer.gov.au/industry/registers/resources/reviews/review-electricity-transmission-service-standards-incentive-schemes#:~:text=The%20AER%20committed%20to%20commencing,network%20service%20providers%20(TNSPs).

[66] The propensity of AER to amend the STPIS is confirmed by the Issues Paper published on 8 December 2023. In the document, AER states that *"the MIC does not appear to be currently working as intended"* and "*there is a case to amend the MIC"*. With regard to the NCC, AER notices that the number of projects undertaken by the TNSPs is quite small and the amount of resources awarded is tiny if compared to the overall maximum allowed revenues of the network service providers. In light of the size of network augmentation required by the integration of renewables, the complexity of administering the mechanism and a stronger involvement of AEMO in network planning, AER is doubtful about the relative importance of the NCC and is considering whether to amend or discontinue it altogether. See AER (2023c), *Issues Paper – Transmission STPIS Review: MIC and NCC*, Commonwealth of Australia, December, available at: https://www.aer.gov.au/system/files/2023-12/AER%20Issues%20paper%20-%20Transmission%20STPIS%20Review%20-%20MIC%20and%20NCC%20-%208%20December%202023.pdf.

5 Task 2: Stakeholders' consultation on the general features of the proposed scheme

According to the Terms of Reference, Task 2 included:

a) A consultation with regulators to collect feedback on the draft set of principles provided by ACER and their consequent implementation implications;
b) A consultation with TSOs to collect feedback on the draft set of principles provided by ACER and their consequent implementation implications;
c) A public consultation with stakeholders, organised in cooperation with ACER, on the draft set of principles provided by ACER, to be run in an inclusive and transparent manner.

The set of principles referred to in all three consultations were in fact those developed by the FSR in the previous assignment, which were outlined in Section 3.2 above and which ACER confirmed at the beginning of Task 2.

The rest of this section is structured as follows:

- Section 5.1 describes the consultation with regulators and TSOs carried out between October and December 2023 on the draft set of principles provided by ACER and their consequent implementation implications;
- Section 5.2 describes the public consultation with stakeholders carried out between November and December 2023 on the draft set of principles provided by ACER and their consequent implementation implications.

5.1 Consultations with regulators and TSOs

In agreement with ACER and in order to reduce the total timespan of the consultations envisaged in this task, consultations with regulators and TSOs were run in an overlapping time framework. Therefore, between October and December 2023, the FSR ran a joint consultation involving regulators and TSOs on the incentive-based scheme outlined in Section 3.2.

In order to reach the relevant experts in national regulatory authorities and TSOs respectively, it was decided that FSR contacted the Council of European Energy Regulators (CEER) and the European Network of Transmission System Operators for Electricity (ENTSO-E), asking them to alert their respective individual members of the consultation.

The consultation of regulators was launched through CEER on 11 October 2023, with a deadline of 27 October 2023, later postponed, firstly to 3 November 2023 and then again to 24 November 2023. The consultation of TSOs was launched through ENTSO-E on 12 October 2023, with the same deadline, equally postponed twice. The FSR team presented the consultation to a number of regulators' representatives during an ACER workshop on accelerating network development for energy transition, on 23 October 2023.

The consultations were run using a questionnaire accessible on an online platform. The questionnaire used for the consultation of regulators and TSOs is presented in Annex II.

Fourteen regulators and one TSO from 14 European countries participated in the consultation[67]. The quality of the answers to the consultation was heterogeneous and not always satisfactory. Some respondents did not answer some of the questions in the consultation or provided answers that were unclear or not relevant/related to the questions.

Based on the results of the survey, it is possible to state that the CAPEX bias and the lack of incentives to implement innovative and more efficient solutions are a concern for many regulators, but not for all of

[67] Six TSOs participated in the public consultation with stakeholders. See Section 5.2 for more details.

them, as several regulators did not share such a concern. The majority of regulators and the TSO participating in the consultation supported the idea that a share of the congestion income could be used to incentivise TSOs efficiently to expand interconnection capacity[68]. Similarly, a clear majority of respondents argued that benefits other than congestion rents are too difficult to quantify accurately to be used to set incentives.

All respondents agreed that the sharing of cost savings associated with innovative and more efficient solutions to system needs with respect to more traditional solutions could be effective in promoting these innovative and more efficient solutions to system needs. Some of the respondents even argued that this approach would be easier and less risky to implement than a scheme relying on the sharing of benefits. However, a vast majority of the respondents identified some critical aspects in the implementation of the proposed scheme. Concerns related mostly to information asymmetry and insufficient resources and/or competences for the regulators, which would make the identification of system needs and the assessment of the alternative solutions difficult. A vast majority of respondents argued that a move to the proposed scheme would increase implementation complexity, in particular due to the need to identify system needs, assess alternative solutions and report more information. Some respondents claimed that this would penalise TSOs as well. However, one regulator argued that the higher complexity of the proposed scheme might be justified by the additional benefits it would bring vis-à-vis traditional regulatory practice. A few regulators expressed concerns about other possible challenges beyond implementation, but failed to be sufficiently specific on their claims. Equally, regulators did not provide many ideas on how to overcome the challenges that go beyond implementation. In this regard, one regulator openly suggested endowing regulators with additional specialised resources and improving communication with the TSOs.

5.2 Public consultation with stakeholders

The public consultation with stakeholders was launched on 9 November 2023, through the publication of a notice on the FSR website, which was given visibility through the inclusion of a piece of news in the FSR Newsletter. A public webinar was organised on 24 November to allow interested parties to seek clarifications. The deadline for participating in the consultation, initially set on 1 December, was postponed twice until the end of the year to provide further opportunities for stakeholders to participate.

This consultation was conducted through a questionnaire available on an online platform. The questionnaire used for the public consultation was similar to the one used for the consultation of regulators and TSOs and is presented in Annex III.

Nineteen entities from nine European countries and two non-European countries participated in the consultation. Seven of them were members of research centres, think tanks or universities, six were TSOs, five were DSOs or energy companies and one was an industry association. Interestingly, some TSOs, who did not participate in the consultation dedicated to regulators and TSOs, took the opportunity of the public consultation with stakeholders to express their views.

Respondents generally shared the view that the proposed scheme could provide valuable incentives to TSOs to opt for more efficient, innovative solutions that align well with the needs of the energy transition. However, many of the respondents highlighted that the implementation of such a scheme might pose some significant challenges, including in terms of:

- the definition of system needs and the identification of the traditional standard solutions;
- the interlinkages between the different system needs;

[68] However, the compatibility of the use of congestion income to incentivise TSOs with the provisions of Article 19(2) of Regulation (EU) 2019/943, defining the priority objectives for the allocation of any revenues resulting from the allocation of cross-zonal capacity, would need to be assessed.

- the uncertainty regarding future costs and the need to take such uncertainty into account when designing the proposed scheme;
- the relationship of the proposed scheme with output-based regulation;
- the calibration of the sharing factor and the profile with which the incentive is paid.

With regard to the identification of system needs, many respondents from the TSO community highlighted that only the TSOs possess the information for such an identification and that, therefore, they should be in the driving seat for this process, while regulators should only have the role of approving or not their proposals. In addition, some TSOs participating in the consultation argued that the focus of regulation should not be exclusively on costs, since sometimes more expensive solutions also provide additional system benefits.

Respondents from the academic community had normally a positive attitude towards the proposed scheme, but highlighted: the possibility of perverse strategic incentives for the TSOs; the need to calibrate well the incentives for cost efficiency and service quality; the necessity better to specify the meaning and boundary of system need(s); the necessity to specify how the comparison of alternative solutions is done; the arbitrariness of the choice of the traditional efficient solution; the need to consider interlinkages between the various system needs; and the importance of considering an extension of the proposed approach to DSOs.

Interestingly, the majority of network companies and energy companies participating in the consultation believe that the current regulatory approach in their countries does not lead to the TSO(s) opting for capital-intensive solutions to system needs. In fact, many of them argued that the regulatory framework in place in their country already today provides good incentives. This is the case, according to the respondents to the consultation, for instance, of Italy and Portugal, and possibly also Spain and Belgium. A bit different is the position of almost all of the academics and researchers answering the consultation and of the industry association that answered the consultation: they tend to believe that the current regulatory approaches might not provide sufficient incentives for innovation and efficiency.

Apart from two (out of eleven) cases, all the network companies and energy companies responding to the consultation did not explicitly agree with the idea that congestion income could be used to incentivise efficiently the TSOs. Most of them argued that changing the current rules in Europe on the use of congestion income should be avoided. They supported this view by claiming that an incentive linked to congestion income would increase risks for the TSOs and might even provide an incentive contrary to the pursued goal. Rather than sharing congestion income, one respondent suggested mandating more transparency on the utilisation of physical assets as a way to induce TSOs tackling congestion more efficiently.

There was no clear majority among respondents with regard to the claim that benefits associated with solutions addressing system needs could be quantified in a sufficiently accurate way in order to use them as a reference for regulatory incentives. Some TSOs and the industry association answering to the consultation maintained the view that cost-benefit analyses are now quite robust and can provide a good approximation of the benefits associated with specific projects. Other TSOs were hesitant to share such a position. Interestingly, some respondents implicitly bought the idea, which is at the core of the proposed scheme, that a cost reduction is a benefit that can be estimated and used as a driver for the provision of incentives.

A large majority of respondents agreed that the sharing of cost savings of innovative and more efficient solutions to system needs with respect to more traditional solutions, as outlined in Section 3.2, could be effective in promoting these innovative and more efficient solutions to system needs. However, some TSOs underlined that cost reductions should not be the only guiding principle, while one TSO insisted on the importance of adopting an output-based approach to network regulation in order to align better the interest of TSOs with that of the system.

Respondents also identified a number of critical aspects in the implementation of the proposed scheme, in particular with respect to: the identification of system needs by the regulators and the estimation of the cost of the traditional efficient solution; the definition of the system needs in a coherent way; the quantification of costs and benefits of different solutions; and the calibration of the sharing factor. These critical aspects are mostly associated with the lack of adequate knowledge and resources of the regulators and the intrinsic complexity of certain activities (e.g., uncertainty of the future).

A few respondents underlined that the standard costs provided by ACER are not a very good reference for being used as a benchmark for calibrating incentives, as there is significant variability across projects and countries. On top of that, some respondents stressed the fact that initial cost projections often underestimate the actual costs of a project.

The vast majority of network companies and stakeholders argued that the proposed scheme would present a higher degree of complexity. This view is not shared by the majority of the research centres answering the consultation, though. Several respondents identify the assignment to regulators of the responsibility of identifying system needs and determining the respective costs as a major source of additional complexity. However, a couple of TSOs argued that the increased complexity could be acceptable as it might deliver superior benefits in addressing the challenges of the energy transition.

More than half of the respondents highlighted additional challenges beyond implementation difficulties, but they were not always clear about what they referred to. In particular, they mentioned: incentives for the TSOs to inflate the estimated cost of the standard solution, raise the cost of the innovative solution and spend less than anticipated; insufficient incentives for promoting the use of flexibility by the system operator; insufficient incentives to promote neutrality between OPEX and CAPEX and to avoid project delays; necessity to make case-by-case assessments of the suitability of a specific solution; difficulties in providing regulators with the resources to mirror the analytical and planning skills of TSOs; difficulties in using congestion rents to provide optimal incentives; and the need to ensure recovery of costs associated with innovation whether successful or not.

Some respondents provided a few suggestions to move forward: sharing best practices, in particular about the cost-benefit assessment of non-wire solutions; a larger use of positive incentives (i.e., rewards) rather than negative incentives (i.e., penalties) to promote innovation; the limitation of the application of the proposed scheme to specific projects; the trialling of the proposed scheme on the field before taking a final view on its merits; the possibility for EU Member States to adjust the proposal to their national context; and the addition of elements to the scheme that foster the use of flexibility by system operators.

6 Task 3: Develop examples of investment remuneration via benefit sharing and presentation of results

According to the Terms of Reference, Task 3 included:

a) The development of at three sample cases of benefit-sharing applied to plausible investments of different nature with a high benefit-to-cost ratio aimed at increasing the efficient usage of existing infrastructure. The sample cases should be used to illustrate all the elements that a regulator needs for an informed decision and the positive and negative aspects of such benefit-based remuneration for both the project promoters (i.e., TSOs) and network users. The sample cases are meant for illustrative purposes and therefore do not necessarily refer to actual investments;
b) A consultation with regulators to collect feedback on the sample cases and the principles;
c) A consultation with TSOs to collect feedback on the sample cases and the principles;
d) The finalisation of the sample cases, preparation of a presentation and organisation, in cooperation with ACER, of a public webinar where these sample cases, alongside the Final Report, are presented.

The rest of this section is structured as follows:

- Section 6.1 describes the three sample cases where the proposed approach has been applied. The critical aspects of the proposed scheme have already been discussed in Sections 3.4 and 3.5.
- Section 6.2 describes the consultation carried out in February and March 2024 with regulators, TSOs and open to all stakeholders regarding the implementation aspects of the proposed scheme, also on the basis of the examples provided in the sample cases.

The questions included in the consultation can be found in Annex IV.

6.1 Sample cases of benefit-sharing

In this section, we present and elaborate on three sample cases of the promotion of more efficient, innovative solution(s) to system needs through benefit sharing, according to the proposed scheme, as outlined in Section 3.2.

In presenting the sample cases we illustrate all the elements that a regulator needs to consider for taking an informed decision. We envisage that the sample cases will be mainly for illustrative purposes and therefore will not necessarily refer to actual projects.

The following sample cases, each of them referring to a specific system need, have been developed:

- Increasing the transmission capacity between different bidding zones, in order to expand cross-zonal exchanges (market integration);
- Increasing the connection capacity for onshore renewable-based generation, in order to support the penetration of such generation in the energy system (decarbonisation);
- Preserving an adequate contingency reserve in a congested section of the network, in order to accommodate more energy flows (security of supply).

Table 3 illustrates the information and other elements that a national regulatory authority has to acquire, take into account or define in implementing the proposed benefit-based incentive scheme to promote more efficient, innovative solutions to the identified system needs. When relevant, the table contains short descriptions of how the proposed scheme has been applied to the sample cases. These descriptions are meant to increase the transparency of the implementation of the proposed scheme in the sample cases and refer to specific choices with regard to some parameters. These choices are to some extent judgmental and open to discussion, as it was highlighted in Section 3.4. Tables 4, 5 and 6 present how the proposed scheme would be implemented with reference to the three sample cases listed above.

Table 3: Information or elements to acquire and take into account or to be defined by the regulator to implement the proposed benefit-based incentive scheme.

	Information or element	Description
1	System need(s) to address	Identification by the regulator(s), possibly supported by the TSO(s), of the system need(s) to be addressed by the TSO(s)
2	Traditional standard solution to address the identified system need(s)	Identification by the regulator(s), possibly supported by the TSO(s), of the traditional standard solution to address the identified system need(s)
3	Techno-economic characteristics of the traditional standard solution	Description of the main technical and economic characteristics of the traditional standard solution to address the identified system need(s): • Investment costs associated with the deployed assets; • Useful life of the deployed assets; • Operation and maintenance costs associated with the traditional standard solution
4	Notional/regulatory life of the infrastructure involved in the traditional standard solution	Time span over which capital investment is fully depreciated from a regulatory perspective
5	Extent to which the traditional standard solution delivers the identified system need(s)	Share of the identified system need(s) that the traditional standard solution is able to deliver
6	Revenue requirements to cover the capital and operating costs of the traditional standard solution in each year of the notional/regulatory life	Total of a) capital depreciation; b) regulated return on the regulatory asset base[69]; and c) operating costs of the traditional standard solution in each year of the notional/regulatory life Straight-line depreciation and a WACC of 5.26% (to calculate the return on capital expenditure) are assumed for the sample cases
7	Net present value of the revenue requirements presented in item 6, using the appropriate discount rate[70]	For the sample cases, a (real) social discount rate of 2% is applied to the revenue requirements identified in item 6

69 The return on capital expenditure is typically calculated using the WACC.

70 As indicated in Section 3.4.1, one needs to choose a discount rate among possible alternatives.

8	More efficient, innovative solution to the identified system need(s)	Identification by the TSO(s), and approval by the regulator, of the more efficient, innovative solution to address the identified system need(s)
9	Techno-economic characteristics of the identified more efficient, innovative solution	Description of the main technical and economic characteristics of the traditional standard solution to address the identified system need(s): • Investment costs associated with the deployed assets; • Useful life of the deployed assets; • Operation and maintenance costs associated with the innovative solution
10	Notional/regulatory life of the infrastructure involved in the more efficient, innovative solution	Time span over which capital investment is fully depreciated from a regulatory perspective
11	Extent to which the more efficient, innovative solution delivers the identified system need(s)	Share of the identified system need(s) that the more efficient, innovative solution is able to deliver
12	Revenue requirements to cover the capital and operating costs of the more efficient, innovative solution in each year of the notional/regulatory life of the traditional standard solution	Total of a) capital depreciation; b) regulated return on the regulatory asset base[71]; and c) operating costs of the more efficient, innovative solution in each year of the notional/regulatory life Straight-line depreciation and a WACC of 5.26% (to calculate the return on capital expenditure) are assumed
13	Net present value of the revenue requirements presented in item 12, using the appropriate discount rate[72]	For the sample cases, a (real) social discount rate of 2% is applied to the revenue requirements identified in item 12

[71] See footnote 69.

[72] See footnote 70.

14	Comparison of the net present values of the revenue requirements of the traditional standard solution (item 7) and of the revenue requirements of the more efficient, innovative solution (item 13), adjusted to the extent that the two solutions deliver the identified system need(s)	The unadjusted comparison is equal to the difference between the value of item 7 and the value of item 13 The adjusted comparison is obtained by raising the net present values of the revenue requirements of both the traditional standard solution and the more efficient, innovative solution by the inverse of the share of the identified system need(s) that the traditional standard solution and the more efficient, innovative solution are able, respectively, to deliver (items 5 and 11 above). For example, if the traditional standard solution can deliver 95% of the identified system needs while the more efficient innovative solution can deliver only 90% of the identified system needs, the adjusted value is calculated by multiplying the net present value of the allowed revenues of the traditional standard solution (item 7) by 1/0.95 and the net present value of the more efficient innovative solution (item 13) by 1/0.9[73]
15	Definition of the sharing factor	
16	Determination of the net present value of the incentive, by applying the sharing factor (item 15) to the cost difference (item 14)	
17	Determination of the profile of the incentive	Value of the yearly incentive paid during the incentivisation period An incentivisation period of 2 years, a constant annual incentive over this period and a WACC of 5.26% (to calculate the actual value of the incentive from the net present value previously obtained – item 16) is assumed for the sample cases

[73] An alternative adjustment approach would be to multiply the net present value of the allowed revenues of the traditional standard solution by the share of the identified system need(s) that the more efficient, innovative solution is able to deliver, divided by the share of the identified system need(s) that the traditional standard solution is able to deliver (in our example 0.9/0.95). This value would then be compared with the allowed revenues of the more efficient, innovative solution. It is important to note that this alternative approach would provide a different result than the one proposed in the table.

Table 4: Application of the proposed regulatory scheme to the first sample case.

	Information or element	**Increasing the transmission capacity between different bidding zones**
1	System need(s) to address	Increase in the cross-border capacity by 600 MW (the two neighbouring countries are connected by three lines, one of them being more heavily congested than the other two)
2	Traditional standard solution to address the identified system need(s)	Deployment of a new, 300 km-long, single circuit, 400 kV overhead line parallel to the most congested interconnection line Upgrade of the two substations at the end of the new line and deployment of a new 400/220 transformer
3	Techno-economic characteristics of the traditional standard solution	Investment costs: 182,374,000 euro (145,500,000 euro for the overhead line; 32,048,000 euro for the upgrade of the 2 substations; 4,826,000 euro for the new 400/220 transformer) Useful life of the assets deployed: 40+ years Operation and maintenance costs: 1,823,740 euro/year (1% of CAPEX)
4	Notional/regulatory life of the infrastructure involved in the traditional standard solution	40 years
5	Extent to which the traditional standard solution delivers the identified system need(s)	100% of the time
6	Revenue requirements to cover the capital and operating costs of the traditional standard solution in each year of the notional/regulatory life	447,181,048 euro
7	Net present value of the revenue requirements presented in item 6, using the appropriate discount rate	322,953,858 euro
8	Identification by the TSO of the more efficient, innovative	Deployment of a dynamic line rating system over the three existing interconnection lines (overall length: 700 km)

	solution to the identified system need(s)	Deployment of a phase-shifting transformer (PST) over the more congested line
9	Techno-economic characteristics of the identified more efficient, innovative solution	Investment costs: 37,000,000 euro in year 1; 7,000,000 euro in year 11, 21 and 31 Useful life of the assets deployed: 10 years for the DLR system, 40 years for the PST Operation and maintenance costs: 1,000,000 euro/year (10% of CAPEX for DLR, 1% of CAPEX for PST)
10	Notional/regulatory life of the infrastructure involved in the more efficient, innovative solution	5 years for the DLR system 40 years for the PST
11	Extent to which the solution delivers the identified system need(s)	73% of the time
12	Revenue requirements to cover the capital and operating costs of the more efficient, innovative solution in each year of the notional/regulatory life of the traditional standard solution	133,242,000 euro
13	Net present value of the revenue requirements presented in item 12, using the appropriate discount rate	95,054,363 euro
14	Comparison of the net present values of the revenue requirements of the traditional standard solution (item 7) and of the revenue requirements of the more efficient, innovative solution (item 13), adjusted to the extent that the two solutions deliver the identified system need(s)	Unadjusted comparison: 227,899,496 euro Adjusted comparison: 192,742,402 euro
15	Definition of the sharing factor	20%
14	Determination of the net present value of the incentive,	Unadjusted net present value of the incentive: 45,579,899 euro

	by applying the sharing factor (item 15) to the cost comparison (item 14)	Adjusted net present value of the incentive: 38,548,480 euro
17	Determination of the profile of the incentive	Unadjusted yearly incentive: 23,373,966 euro/year to be paid for 2 years Adjusted yearly incentive: 19,768,163 euro/year to be paid for 2 years

Table 5: Application of the proposed regulatory scheme to the second sample case.

	Information or element	**Increasing the onshore connection capacity for renewable-based generation**
1	System need(s) to address	Increase in the connection capacity for onshore renewable-based generation by 100 MW (the deployment of an onshore wind farm causes congestion in a nearby segment of the transmission grid, whose capacity must be expanded)
2	Traditional standard solution to address the identified system need(s)	Deployment of a new, 50 km long, single circuit, 220 kV overhead line parallel to the existing one Upgrade of the two substations at the end of the new line
3	Techno-economic characteristics of the traditional standard solution	Investment costs: 30,718,000 euro (21,450,000 euro for the overhead line; 9,268,000 euro for the upgrade of the 2 substations) Useful life of the assets deployed: 40+ years Operation and maintenance costs: 307,180 euro/year (1% of CAPEX)
4	Notional/regulatory life of the infrastructure involved in the traditional standard solution	40 years
5	Extent to which the traditional standard solution delivers the identified system need(s)	100% of the time
6	Revenue requirements to cover the capital and operating costs of the	75,320,536 euro

	traditional standard solution in each year of the notional/regulatory life	
7	Net present value of the revenue requirements presented in item 6, using the appropriate discount rate	54,396,442 euro
8	Identification by the TSO of the more efficient, innovative solution to the identified system need(s)	Deployment of a dynamic line rating system over the existing line (length of the line: 50 km)
9	Techno-economic characteristics of the identified more efficient, innovative solution	Investment costs: 1,000,000 euro in year 1, 11, 21, 31 Useful life of the assets deployed: 10 years Operation and maintenance costs: 100,000 euro/year (10% of CAPEX)
10	Notional/regulatory life of the infrastructure involved in the more efficient, innovative solution	5 years for the DLR system
11	Extent to which the solution delivers the identified system need(s)	90% of the time
12	Revenue requirements to cover the capital and operating costs of the more efficient, innovative solution in each year of the notional/regulatory life of the traditional standard solution	8,526,000 euro
13	Net present value of the revenue requirements presented in item 12, using the appropriate discount rate	5,989,911 euro
14	Comparison of the net present values of the revenue requirements of the traditional standard	Unadjusted comparison: 48,406,531 euro

	solution (item 7) and of the revenue requirements of the more efficient, innovative solution (item 13), adjusted to the extent that the two solutions deliver the identified system need(s)	Adjusted comparison: 47,740,985 euro
15	Definition of the sharing factor	20%
16	Determination of the net present value of the incentive, by applying the sharing factor (item 15) to the cost comparison (item 14)	Unadjusted net present value of the incentive: 9,681,306 euro Adjusted net present value of the incentive: 9,548,197 euro
17	Determination of the profile of the incentive	Unadjusted yearly incentive: 4,964,699 euro/year to be paid for 2 years Adjusted yearly incentive: 4,896,315 euro/year to be paid for 2 years

Table 6: Application of the proposed regulatory scheme to the third sample case.

	Information or element	Ensuring security of supply (N-1 criterion)
1	System need(s) to address	Preserve an adequate contingency reserve in a congested section of the transmission network (6 lines, 2 at 400 kV and 4 at 220 kV, connected to a single node, plus other 4 nearby lines at 220 kV) so that the system can withstand the loss of one of the main transmission elements (N-1 criterion)
2	Traditional standard solution to address the identified system need(s)	Deployment of a new, 100 km-long, single-circuit, 400 kV overhead line linking two existing lines Deployment of a new, 200 km-long, double circuit, 220 kV overhead line linking two existing lines Deployment of a new, 150 km-long, single circuit, 220 kV overhead line linking two existing lines Reconductoring of 6 existing overhead 220 lines for a total length of 800 km to increase their capacity by 30%

		Addition of a 400/220 transformer Refurbishment/upgrade of the substation connecting 6 existing lines (major intervention) Refurbishment/upgrade of 8 substations (minor interventions)
3	Techno-economic characteristics of the traditional standard solution	Investment costs: 527,028,000 euro, of which: • 51,000,000 euro for the new, 100 km-long, single-circuit, 400 kV overhead line • 116,400,000 euro for the new, 200 km-long, double-circuit, 220 kV overhead line • 67,800,000 euro for the new, 150 km-long, single circuit, 220 kV overhead line • 240,000,000 euro for the reconductoring of 6 existing lines • 5,080,000 euro for the new 400/220 transformer • 16,900,000 euro for the refurbishment of the substation at the centre of the congested section • 29,848,000 euro for the refurbishment of the 8 substations connected to the existing and new lines involved in the deployment of the standard solution Useful life of the assets deployed: 40+ years Operation and maintenance costs: 5,270,280 euro/year (OPEX = 1% CAPEX)
4	Notional/regulatory life of the infrastructure involved in the traditional standard solution	40 years
5	Extent to which the traditional standard solution delivers the identified system need(s)	100% of the time
6	Revenue requirements to cover the capital and operating costs of the traditional standard solution in each year of the notional/regulatory life	1,235,221,456 euro

7	Net present value of the revenue requirements presented in item 6, using the appropriate discount rate	897,261,888 euro
8	Identification by the TSO of the more efficient, innovative solution to the identified system need(s)	Deployment of a 250 MW(h) battery energy storage system (BESS) at the node where six of the involved lines connect Refurbishment/upgrade of the substation connecting 6 existing lines and the BESS
9	Techno-economic characteristics of the identified more efficient, innovative solution	Investment costs: 237,500,000 euro, of which: • 187,500,000 euro in year 1 • 50,000,000 euro in year 21 to replace the batteries Useful life of the assets deployed: • Batteries: 20 years • Remaining infrastructure: 40+ years Operation and maintenance costs: 5,000,000 euro (OPEX = approx. 2% CAPEX)
10	Notional/regulatory life of the infrastructure involved in the more efficient, innovative solution	15 years for the BESS
11	Extent to which the solution delivers the identified system need(s)	100% of the time
12	Revenue requirements to cover the capital and operating costs of the more efficient, innovative solution in each year of the notional/regulatory life of the traditional standard solution	531,193,750 euro
13	Net present value of the revenue requirements presented in item 12, using	404,629,073 euro

	the appropriate discount rate	
14	Comparison of the net present values of the revenue requirements of the traditional standard solution (item 7) and of the revenue requirements of the more efficient, innovative solution (item 13), adjusted to the extent that the two solutions deliver the identified system need(s)	492,632,815 euro
15	Definition of the sharing factor	20%
16	Determination of the net present value of the incentive, by applying the sharing factor (item 15) to the cost comparison (item 14)	98,526,563 euro
17	Determination of the profile of the incentive	Yearly payment (if incentive paid over 2 years in equal instalments): 50,525,704 euro

6.2 Consultation with regulators, TSOs and other stakeholders on implementation aspects and sample cases

In agreement with ACER and in order to reduce the total timespan of the consultations envisaged in this task, it was decided to merge the consultations of regulators, TSOs and other stakeholders. Such a combined consultation was launched on 31 January 2024, with a deadline for responses on 8 March 2024. Both CEER and ENTSO-E were alerted of the start of the consultation, with an invitation to communicate this to their respective members. Moreover, those individuals who participated in the consultations in Task 2 were approached directly via email. The consultation was advertised by means of a piece of news on the FSR website and mentioned multiple times in the FSR Newsletter.

The consultation was again run using a questionnaire accessible on an online platform. The questionnaire used for the consultation is presented in Annex IV[74].

A webinar was held on 15 February 2024 to provide any needed clarification to those interested in the consultation.

[74] The third sample case described in Section 5.3 was not part of this consultation, as the delay in obtaining the necessary information and data meant that this sample case was developed in parallel to the consultation.

Ten entities answered the consultation: two TSOs, three DSOs or energy companies, two industry associations, two regulators and one consultant. Representation of those actors most directly involved (i.e., TSOs and regulators) was thus limited and this may impact the relevance of the results of the consultation.

The results of this consultation, which was mostly focused on the implementation aspects of the proposed scheme, were somewhat in line with those of the previous consultations and highlighted the existence of some concerns among regulators, TSOs and other stakeholders about the implementation of the proposed scheme.

To start with, a clear majority of the respondents believed that the identification of system needs would pose a significant challenge to regulators and that this challenge would be greater than that associated with traditional system planning, because of the larger amount of knowledge and expertise required and because of the additional complexity due to the necessity of prioritising needs and projects. In particular, several respondents highlighted that network operators currently have the knowledge and expertise required to perform this exercise, while regulators would need support. If the feedback of the participants in the consultation were, in fact, reflective of reality, this would depict a disturbing situation, in which regulators are currently unable properly to scrutinise the basis on which the network plans are prepared by TSOs and which, eventually, would result in network expansion and reinforcements to be paid through the tariff system.

According to a broad majority of the respondents, the identification of the traditional standard solution would represent a significant challenge as well; nonetheless, many of them believed that experience in addressing similar needs could help. Those with a more negative view claimed that a detailed assessment of each specific case is necessary to identify the best solution or that current changes in the energy system are so significant that the past is of little guidance.

A clear majority of respondents believed that the definition of the costs of the traditional standard solution would also represent a significant challenge for regulators. Only half (i.e., four out of eight) of those recognising the magnitude of this challenge thought that experience and unit cost indicators provided by ACER could assist in overcoming such challenge, because of the variability and volatility of investment costs, especially in the current difficult macroeconomic and geopolitical context. More in general, the specific characteristics of each project and the rapid evolution in input prices imply that the unit cost indicators provided by ACER can help with the estimation of the costs of the standard solution only to a certain degree.

A clear majority of respondents believed that it would be difficult for regulators to assess and endorse the more efficient, innovative solutions proposed by the TSOs. For half of this majority, this exercise would be more difficult than the approval of new investments to be included in the RAB, because of the high level of knowledge and expertise required for such an assessment, something that currently regulators do not have and for which they would be dependent on network operators. Ranking needs and priorities would make the exercise more complex.

With regard to the design choices of the proposed scheme, respondents to the consultation provided some feedback on the discount rate, the sharing factor and the incentive profile to adopt.

A majority of respondents supported the use of the 4% social discount rate proposed by ACER for cost-benefit analysis or a country-specific SRTP to compute the net present value of the stream of annual allowed revenues, because the aim of the exercise is to choose what is best in the interest of society and because considerations about risks are not relevant. Only a couple of respondents supported the use of the WACC, mostly because it would ensure consistency with the treatment of other investments and existing assets. One respondent suggested discounting the network operator's expenditure rather than the allowed revenues.

Half of the respondents argued in favour of a fixed sharing factor, while a large minority was in favour of a sharing factor that increases with the extent of savings. The former was appreciated for its simplicity and the stability/predictability it provides, while the latter was appreciated for its ability to provide stronger incentives compatible with the larger social benefits associated with more innovative (and potentially riskier) solutions. A majority of respondents argued that the sharing factor should be in the range of 10-30%, while two respondents favoured a much higher factor (50%). Those in favour of the 10-30% range claimed that this is a typical sharing factor in current regulatory frameworks and that, based on experience, this level is sufficient to induce network operators to act. Moreover, as the primary goal of regulation is to lower grid charges and uncertainty about future developments, they claimed caution should be exercised to avoid providing too generous incentives. On the contrary, those supporting higher values for the sharing factor argued that society needs to provide more incentives due to the urgency of preparing the grid for the energy transition.

While some answers were not fully clear, the majority of respondents argued in favour of a rapid disbursement of the incentive payments (1-3 years), as this would provide stronger incentives for the network operator. One respondent, on the contrary, called for a disbursement over the amortisation period of the avoided investment (in this case the incentive should be properly re-valued, though).

Finally, respondents listed these (additional) implementation challenges: the difficulty of changing the regulatory mindset; the complexity of correctly comparing traditional and innovative solutions; and the need to provide some degrees of flexibility to deal with exceptional circumstances while providing certainty to network operators.

7 Conclusions

This Report illustrates the activities performed by the FSR in defining and consulting on the implementation features of the incentive scheme outlined in a previous assignment[75] and summarised in Section 3.2, which aims at promoting the deployment of more efficient, innovative solutions to address identified system needs in the European liberalised electricity sector.

The quest for more efficiency and innovation has always been an objective of the economic regulation of the electricity sector, and in particular of regulated activities. However, with the substantial investment in grids required to accompany and enable the energy transition, the promotion of more efficient and innovative approaches to electricity network system needs becomes imperative. The significant progress in technology and digitalisation observed in recent years makes such innovation possible. This is also the message emerging from the *EU Action Plan for Grids*, issued in November 2023, where the European Commission refers to investment needs in electricity transmission and distribution networks by 2030 of 584 billion euros.

Regulators in Europe and beyond are increasingly aware of the challenges associated with a rapid transformation of the energy system and the need to explore new approaches to support such a transformation. Some of them have also taken concrete action, exploring or even adopting new regulatory schemes to foster innovation and efficiency in electricity transmission and distribution.

The scheme proposed by the FSR in the previous assignment and whose implementation features are presented in this Report is not intended to replace the current electricity transmission regulatory framework, but rather to equip regulators with an additional tool to be used where there is the perception that 'breakthrough' technological solutions are available and TSO(s) should be incentivised to look for and deploy them at scale.

Concerns have been expressed during the several rounds of consultations run during this project regarding the challenges of implementing the proposed scheme, the fact that most regulators are not equipped for such an implementation and that, in fact, TSO(s) should still be in the driving seat in identifying system needs and developing network plans to address them, which regulators have at best limited capacity properly to scrutinise. Taken at face value, such concerns evoke a disturbing situation: in fact, while TSO(s) clearly have superior information regarding the state of the system and, therefore, on where grid development or reinforcements are needed, such needs and the required actions to address them should be properly examined by regulators to ensure that the whole process is run in the best interest of grid users and, eventually, consumers, current and future.

Moreover, most of the implementation features of the proposed scheme do not seem to be more challenging for regulators and TSO(s) than the implementation of more traditional forms of regulation, if properly undertaken, with regulators playing the required role of assessing the identified system needs and the way in which they are to be addressed.

If the problem with the current role of NRAs in the electricity network planning process and, *a fortiori*, in an enhanced scheme to promote more efficient, innovative solutions addressing system needs is one of resources, the opportunity for Member States to invest more resources in their NRAs seems a high-return one. Such an investment would probably run into a few tens of million euros a year at the EU level. However, a better scrutiny of the network developing planning process and the implementation of a benefit-based regulatory scheme might deliver savings for electricity grid users and consumers in the order of hundreds of millions of euros, if such improved role of NRAs were able to result in more efficient solutions reducing electricity network development costs by even a few percentage points.

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75 See FSR (2023), *op. cit*.

The size of the potential economic savings, together with the possibility to accelerate the integration of the large amount of renewables to be deployed in the EU in the coming years, makes the case for policymakers and regulators to consider the adoption of the proposed scheme or some possible variants of it. Testing its application to a limited set of cases could be a first step, to gather more experience and possibly fine-tune the scheme, before a more extensive application.

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Annex I – Promoting the use of innovative technologies in the provision of electricity transmission services in the USA

The use of incentive regulation for electricity transmission activities in the USA is relatively recent. It was only in the Energy Policy Act of 2005 that Congress added section 219 to the Federal Power Act[76] (FPA), directing the Federal Energy Regulatory Commission (FERC) to establish, by rule, incentive-based rate treatments to promote capital investment in electric transmission infrastructure.

Therefore, in July 2006, FERC issued Order No. 679, amending the Commission's regulations by establishing incentive-based (including performance-based) rate treatments for the transmission of electric energy in interstate commerce by public utilities for the purpose of benefiting consumers by ensuring reliability and reducing transmission congestion, thus increasing the quality and reducing the cost of electricity for consumers.

In November 2012, FERC issued a Policy Statement, 'Promoting Transmission Investment Through Pricing Reform'[77], providing guidance regarding its evaluation of applications for transmission rate incentives under section 219 and Order No. 679.

However, it was only more recently, in 2019, that FERC launched a consultation on the deployment of grid-enhancing technologies (GETs)[78] that increase the capacity, efficiency or reliability of transmission facilities. The consultation sought to identify the challenges to the deployment and implementation of GETs, and what FERC could do regarding those challenges, including regulatory approaches such as incentives or the establishment of standards. The technologies explicitly considered by FERC included, but were not limited to, a) power flow control and transmission switching equipment, b) storage technologies, and c) advanced line rating management technologies.

The consultation was opened by a workshop on 5 and 6 November 2019[79], after which submissions were sought by interested parties on a number of questions as presented in Box A.

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76 The Federal Power Act is a law appearing in Chapter 12 of Title 16 of the United States Code, entitled "Federal Regulation and Development of Power". Enacted as the Federal Water Power Act on June 10, 1920, and amended many times since, its original purpose was to more effectively coordinate the development of hydroelectric projects in the United States. The act created the Federal Power Commission (FPC) (now the Federal Energy Regulatory Commission) as the licensing authority for these plants. The FPC regulated the interstate activities of the electric power and natural gas industries, and coordinated national hydroelectric power activities. The Commission's mandate called for it to maintain reasonable, non-discriminatory and just rates to the consumers.

77 Available at: https://www.ferc.gov/sites/default/files/2020-04/E-3_23.pdf.

78 The GETs currently being discussed in the USA include hardware and software that increase the capacity, efficiency and/or reliability of the transmission grid, such as:

- Dynamic Line Rating, which determines the true, real-time capacity of power lines, which is almost always higher than the static line ratings used widely today;
- Advanced Power Flow Control, which allows operators to reroute power to lines with available capacity, increasing the total power delivered by the system;
- Topology Optimization, which identifies the best grid reconfigurations to reroute flow around bottlenecks, helping to avoid congestion constraints and costs.

79 See: https://www.federalregister.gov/documents/2019/11/06/2019-24169/grid-enhancing-technologies-supplemental-notice-of-workshop.

Box A*: Questions on which FERC consulted following the November 2019 Workshop*

Question 1: Workshop participants identified several types of technologies that are currently capable of being deployed, such as power flow control and transmission switching technologies, dynamic line ratings, and storage as transmission. What other technologies that increase the capacity, efficiency, or reliability of transmission facilities are ready for deployment?

Question 2: Some workshop participants argued that further deployment of technologies that increase the capacity, efficiency, or reliability of transmission facilities can be encouraged with various types of incentives. What types of incentives would encourage the deployment of technologies referred to in Question 1?

Question 3: In the discussion at the workshop of the 'shared savings' approach for the deployment of GETs to existing transmission assets, workshop participants expressed general ratemaking concerns, and identified implementation issues, such as the measurement of benefits and distribution of payments. Please provide comments on the proposed ratemaking structure and any implementation challenges.

Question 4: Referring to the technologies mentioned in Question 1 (power flow control and transmission switching technologies, dynamic line ratings, and storage as transmission) some workshop participants indicated that RTOs/ISOs consider qualitative benefits, including certain reliability and flexibility attributes, in the regional transmission planning process. How do RTOs/ISOs currently measure or consider these benefits? Please provide examples.

Question 5: What software or other changes would an RTO/ISO need to make to implement GETs? As more of these technologies come onto the system, what challenges exist for coordinating their control in terms of analytics, automation, and optimization?

Question 6: Workshop participants discussed the benefits of pilot programs. Should the Commission encourage the testing and deployment of technologies that increase the capacity, efficiency, or reliability of transmission facilities through pilot programs and demonstration projects? If so, is there regulatory support that the Commission could provide to support and encourage such efforts? Could the Commission use its transmission incentives policy to encourage such pilot programs and demonstration projects? If so, please describe how the Commission could do so.

One of the questions put for consultation (Question 3) related to the possibility of introducing 'shared savings' as an incentive to promote the deployment of GETs. Shared shavings would represent a departure from the traditional rate-of-return regulation widely applied in the USA and provide that a portion of the system-wide cost-savings created by an investment in GETs is shared, as an incentive, with the asset owner. It appears that this approach was proposed to FERC, among others, by a coalition of technology providers which claimed that "*under the current regulatory regime, the incentive structure causes utilities to profit more on large capital investments than on smaller ones that may achieve the same objective. This is especially true of the Return on Equity (ROE)-based incentives that are the focus of the Commission's proposals in this rulemaking. In this proceeding we respectfully urge the Commission to review the incentive properties of the existing set of regulations and amend those that do not result in achieving regulatory objectives*"[80].

[80] WATT Coalition and AEE Comments to the Federal Energy Regulatory Commission on Electric Transmission Incentives Policy under Section 219 of the Federal Power Act (Docket No. RM20-10-000), 1 July 2020, available at: https://watt-transmission.org/wp-content/uploads/2020/08/watt-coalition-aee-filing-to-ferc-in-incentives-nopr.pdf.

From the minutes of the workshop, the way in which Question 3 was phrased and the submissions received afterwards, it seems that several stakeholders who participated in the process expressed concerns regarding the introduction of the 'shared savings' approach. For example, PJM[81] expressed concerns that the proposed shared savings incentives would cause it to perform a new, unwanted and statutorily unauthorised role in the ratemaking process, and it would pose other practical implementation challenges. Such concerns seem to be due to the fact that the shared saving approach proposed by FERC would see PJM involved in the *"determination and quantification of incentive amounts"*[82]. Similar concerns were expressed by CAISO, the Californian Independent System Operator, which emphasised that "*the shared savings approach discussed at the Commission's workshop anticipates that RTOs/ISOs would use existing transmission planning processes to evaluate the cost benefit ratio for a proposed project in order to inform the savings that would be shared between a transmission owner and transmission ratepayers. The CAISO conducts production simulation modeling to assess the estimated economic benefits of projects and uses those modeling results to determine whether to pursue a project in the first instance. The CAISO does not use the modeling results to calculate rates or determine how costs should be "shared," nor are they designed for that purpose*"[83]. A group of Independent System Operators also claimed that applying dynamic line rating on transmission lines with no or minimal congestion would only serve to increase wholesale transmission rates with no commensurate benefits.

Having received opposition to its proposed shared savings scheme, with Order No. 881 in December 2021, FERC required transmission providers, both inside and outside of organized markets, to use ambient-adjusted ratings[84] as the basis for evaluating near-term transmission service to increase the accuracy of near-term line ratings[85]. While Order No. 881 does not mandate the adoption of dynamic line ratings – ratings that account for other weather conditions, such as wind, cloud cover and solar heating intensity – the rule does require that organised market operators establish and maintain systems and procedures necessary to allow transmission owners that would like to use dynamic line ratings the ability to do so. The rule acknowledges that dynamic line ratings may deliver incremental benefits and announces that the Commission is opening a proceeding, which it did in February 2022, to continue to build the record and explore the potential for further action on dynamic line ratings.

In the new consultation[86], FERC sought stakeholders' views on whether dynamic line rating should be mandated further to increase the accuracy of USA transmission line ratings, on the trade-offs associated

81 PJM is a Regional Transmission Organisation (RTO) coordinating the movement of wholesale electricity in all or parts of 13 states (Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia and West Virginia) and the District of Columbia in the USA.

82 Post-Workshop Comments of PJM Interconnection, L.L.C. to the Federal Energy Regulatory Commission on Grid-Enhancing Technologies (Docket No. AD19-19-000), 21 February 2020, available at: https://www.pjm.com/-/media/documents/ferc/filings/2020/20200221-ad19-19-000.ashx.

83 Post-Technical Workshop Comments of the California Independent System Operator Corporation to the Federal Energy Regulatory Commission on Grid-Enhancing Technologies (Docket No. AD19-19-000), 14 February 2020, available at: https://www.caiso.com/Documents/Jan14-2022-PostWorkshopComments-ElectricTransmissionIncentives-RM20-10-AD19-19.pdf.

84 Ambient-adjusted ratings are based on forecasted ambient air temperatures and the presence or absence of solar heating, as well as day-time/night-time distinctions.

85 FERC Order No. 881 requires that ambient-adjusted ratings: a) apply to a time period of not greater than one hour; b) reflect up-to-date forecast of ambient air temperature across the time period to which the rating applies; c) reflect the absence of solar heating during night time, i.e. account for day-time/night-time solar heating changes; d) are calculated at least once for each hour; e) reflect updates to sunrise and sunset times used to calculate at least monthly; f) are updated with every five degree Fahrenheit increment of temperature change; and g) address how ambient adjusted ratings for transmission lines interact with system voltage and stability limits, remedial action schemes and system operating limits.

86 Docket No AD22-5.

with the implementation of dynamic line rating[87], and on whether FERC should establish specific criteria for identifying transmission lines that would benefit from the technology.

In a separate consultation, launched in April 2022, FERC proposed to mandate that dynamic line rating be considered as part of a broader long-range transmission planning and cost allocation approach by ISOs. In particular, FERC proposed to require that public utility transmission providers more fully consider two specific technologies in their regional transmission planning and cost allocation processes: dynamic line ratings and advanced power flow control devices.

In the meanwhile, in April 2023, FERC approved plans by CAISO, the New York Independent System Operator and four utilities (Arizona Public Service, Black Hills Power, Louisville Gas and Electric, and Tampa Electric) to use ambient line rating to determine the capacity of their transmission assets as of 2025.

87 A February 2021 study performed by consulting firm The Brattle Group estimated that DLRs, when implemented with other grid-enhancing technologies, could double renewable energy penetration in the wind-rich Southwest Power Pool region. Another study released on April 22 by the USA Department of Energy found that implementing DLRs on just 16 transmission line segments in New York would cut wholesale electricity costs in the state by $1.8 million annually and reduce renewable energy curtailment by 9%.

Annex II – Questionnaire used for the consultation of regulators and TSOs in Task 2

1) Do you have any general comments on the regulatory scheme presented in the FSR report?
2) Do you consider that the current regulatory approach to network investments in your country might result in the TSO(s) opting for capital-intensive solutions to system needs (the ‘CAPEX bias’) and, more generally, does not promote the adoption of innovative and more efficient solutions to system needs by TSO(s)? Do you have any additional comments?
3) Do you agree that the sharing of congestion income could be used to incentivise TSOs efficiently to expand the interconnection capacity? If not, why?
4) Do you agree that the benefits of solutions addressing system needs, apart from the congestion income reflecting part of the benefits resulting from the expansion of the interconnection capacity, are too difficult accurately to quantify in order to use them as a reference for regulatory incentives? Do you have any additional comments?
5) Do you agree that the sharing of cost savings of innovative and more efficient solutions to system needs with respect to more traditional solutions, as outlined in the text above and in the above-mentioned FSR Report, could be effective in promoting these innovative and more efficient solutions to system needs? Do you have any additional comments?
6) Do you see any difficulties in implementing the proposed scheme? If so, which are they?
7) Do you believe that the proposed scheme would present a higher degree of implementation complexity than the regulatory approaches currently in use? If so, why would it be the case?
8) Do you see, beyond implementation difficulties, other challenges with the proposed scheme? If so, which are they? Do you have any idea on how these challenges could be dealt with?
9) Is your jurisdiction currently implementing an incentive-based regulatory framework for electricity transmission, distribution or system operation activities in which the incentives are linked to the achievement of specific performance targets (e.g., the availability of transmission assets or the volumes of non-served energy)? If so, could you please describe this framework in terms of the following aspects?
    a. The performance target(s) to which the incentives are linked
    b. The operators involved (TSO, DSOs, transmission owners)
    c. Whether the performance targets are related to cost savings with respect to a pre-defined budget
    d. The way in which the incentives are calculated.
10) Is your jurisdiction currently implementing or is it planning to implement an incentive-based regulatory framework for electricity transmission, distribution or system operation activities in which the incentives are commensurate to the monetary benefits delivered by specific investments, set of investments or processes aimed at addressing identified system needs (e.g., incentives linked to the additional congestion income associated with interconnection capacity expansions)? If so, could you please describe this framework in terms of the following aspects?
    a. Whether the framework is in place or whether it is planned
    b. If it is planned, when it is expected to enter into force
    c. The identified system needs
    d. The operators involved (TSO, DSOs, transmission owners)
    e. The investments or processes targeted by the framework
    f. The benchmark against which monetary benefits are assessed
    g. The way in which the incentives are defined with respect to assessed monetary benefits
    h. If the framework is in operation, any assessment of its effectiveness.

Annex III – Questionnaire used for the public consultation with stakeholders in Task 2

1) Do you have any general comments on the regulatory scheme presented in the FSR report?
2) Do you consider that the current regulatory approach to network investments in your country might result in the TSO(s) opting for capital-intensive solutions to system needs (the 'CAPEX bias') and, more generally, does not promote the adoption of innovative and more efficient solutions to system needs by TSO(s)? Do you have any additional comments?
3) Do you agree that the sharing of congestion income could be used to incentivise TSOs efficiently to expand the interconnection capacity? If not, why?
4) Do you consider that the benefits of solutions addressing system needs, apart from the congestion income reflecting part of the benefits resulting from the expansion of the interconnection capacity, could be quantified in a sufficiently accurate way in order to use them as a reference for regulatory incentives? Do you have any additional comments?
5) Do you agree that the sharing of cost savings of innovative and more efficient solutions to system needs with respect to more traditional solutions, as outlined in the text above and in the above-mentioned FSR Report, could be effective in promoting these innovative and more efficient solutions to system needs? Do you have any additional comments?
6) Do you see any difficulties in implementing the proposed scheme? If so, which are they?
7) Do you believe that the proposed scheme would present a higher degree of implementation complexity than the regulatory approaches currently in use? If so, why would it be the case?
8) Do you see, beyond implementation difficulties, other challenges with the proposed scheme? If so, which are they? Do you have any idea on how these challenges could be dealt with?

Annex IV – Questionnaire used for the consultation of regulators, TSOs and other stakeholders in the public consultation in Task 3

a) Do you consider that the identification of the system need(s) to which the proposed scheme could be applied poses a significant challenge to regulators, also taking into account that TSOs might support such an identification?

O Yes O No

b) If Yes: do you consider that such a challenge is greater than those associated with general transmission system planning?

O Yes O No

c) If Yes: in which way? ____________________

d) Do you consider that the identification of the traditional standard solution to the identified system need(s) poses a significant challenge to regulators?

O Yes O No

e) If Yes: do you consider that the experience in addressing similar system need(s) in the past can assist in identifying the traditional standard solution to such need(s)?

O Yes O No

f) If No: why? _____________________________

g) Do you consider that the definition of the costs of the traditional standard solution to the identified system need(s) poses a significant challenge to regulators?

O Yes O No

h) If Yes: do you consider that the experience and the unit cost indicators for electricity transmission investments provided by ACER could assist in overcoming this challenge?

O Yes O No

i) If No: why? _____________________

j) Do you consider that regulators would find it difficult to assess and endorse the more efficient, innovative solutions to address the identified system needs proposed by the TSO(s)?

O Yes O No

k) If Yes: do you think that such difficulties are greater than those involved in approving new investments to be included in the Regulatory Asset Base?

O Yes O No

l) If Yes: in which respect? _____________________

m) In your views, which discount rate should be used to compute the net present value of the streams of annual allowed revenues related to the traditional efficient solution and the more efficient, innovative solution to the same system need(s)?

O the WACC

O the SRTP (approximated by the interest rate on government bonds)

O the social discount rate of 4% recommended by ACER for cost-benefit analysis

O Other

n) If Other: Please specify __________________________

o) Please explain the reasons for your choice of the discount rate ___________________

p) Do you consider that the sharing factor should be fixed or should vary – increasing or decreasing – with the extent of the saving delivered by the more efficient, innovative solution?

O Fixed

O Increasing with the savings (progressive)

O Decreasing with the savings (regressive)

q) What level or range for the sharing factor would you consider the most appropriate in the trade-off between providing effective incentives to TSOs and delivering cost-saving benefits to grid users? ___________________________

r) Please explain the reasons for your choice for the level or range of the sharing factor ___________________________

s) Which profile of the incentive would you consider the most appropriate in the trade-off between providing effective incentives to the TSO(s) and delivering cost-saving benefits to grid users? ___________________________

t) Please explain the reasons for your choice for the profile of the incentive to the TSO(s) ___________________________

u) Is there any other aspect not mentioned in the previous questions which you consider particularly challenging for regulators in implementing the proposed scheme? Please, justify your answer. ___________________________

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