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European Union Agency for the Cooperation of Energy Regulators

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Report on Investment Evaluation, Risk Assessment and Regulatory Incentives for Energy Network Projects

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Executive summary

(1) The European Green Deal is targeting a 55% reduction in greenhouse emissions by 2030 and climate neutrality by 2050. In order to reach these goals vast investments in energy networks are necessary in the coming years. Furthermore, the REPowerEU plan set some targets even more ambitiously, which could further emphasise the need for investments.

(2) The timely development of the necessary energy infrastructure strongly depends on the national regulatory frameworks, including the applied risk mitigation methods and regulatory incentives for the network operators. In order to avoid underinvestment or inefficient investment, it is of utmost importance that the investments which bring the highest value for society are identified and implemented. For this purpose, national regulatory frameworks should strive to put in place appropriate regulatory measures, including identification of needs for new transmission capacity, project cost-benefit assessment, risk mitigation, fair remuneration and, where necessary, additional incentives.

(3) Article 17 of Regulation (EU) 2022/869 ('the TEN-E Regulation') aims at avoiding that European priority projects are not planned or implemented by project promoters due to high risk for them. Therefore, the Regulation foresees the possibility of granting project-specific incentives for high-risk projects of common interest ('PCIs'), under the infrastructure categories of electricity transmission, electricity storage, smart electricity grids, smart gas grids and hydrogen infrastructure.

(4) In order for Article 17(5) to apply, several conditions need to be met by a PCI, including that the project is falling under the competence of national regulatory authorities ('NRA'). ACER notes that most electricity transmission projects are regulated. The other energy infrastructure categories listed by the TEN-E Regulation, with few exceptions, at national level either fall under the category of regular regulated transmission assets without any major differentiation (e.g. transmission related projects which qualify as "smart grids" under the TEN-E Regulation) or they are not (or not yet) under NRA's regulatory oversight (e.g. non-TSO energy storage and hydrogen infrastructure projects).

(5) Therefore, ACER focuses on (regulated) electricity transmission projects in this Report and deems that for the infrastructure categories other than electricity transmission it is premature to benchmark best practices and provide targeted recommendations. Accordingly, unless explicitly stated otherwise, the recommendations in this report refer to regulated electricity transmission projects.

(6) Typically, each national regulatory framework provides the same return to all electricity transmission infrastructure projects in the country, irrespective of their individual risk profile or impact. The parameters for setting the weighted average cost of capital ('WACC') vary across the EU Member States. ACER considers that the benchmarking is an important tool in defining or approving the relevant parameters and recommends NRAs to compare the relevant values (like market related risk) with values used in other Member States and justify if they decide to use an outlier value, when setting or approving the parameters.

(7) ACER's findings show that TSOs' risks are generally covered/mitigated in most Member States by the default risk mitigation measures of the national regulatory framework (the means differ across the Member States) and only in a very few instances during the past ten years need for additional incentives due to higher risks were claimed by project promoters to the NRAs[1]. Next to that, the implementation of investments in electricity transmission projects, including PCIs, has rarely been hindered by project promoters' risks[2], rather due to permit granting related reasons, as shown by ACER's monitoring of the progress of the relevant projects[3].

(8) Therefore, ACER concludes that the current national regulatory frameworks, which systematically mitigate risks and – as ACER's findings show – rarely provide different/beneficial treatment based on specific project features (such as high capital expenditure, being interconnection, offshore and/or anticipatory investment), are generally fit for purpose with respect to risk mitigation, and the need for additional project specific incentives has so far been limited. While the need for such incentives may change over time[4], NRAs should apply them only for projects where the default regulatory framework fails to already provide a fair and sufficient risk/revenue balance.

(9) In case of TSOs' requests for incentives on individual projects, NRAs should use the ACER 7-step common methodology for risk identification and risk assessment described in ACER Recommendation No 03/2014[5] . To ensure that the risks to be borne by the project promoters do not become a barrier for the implementation of a PCI, beyond this methodology, NRAs should also take into account the ACER proposals in the same ACER Recommendation on how to mitigate certain transmission system operator's risks (concerning both project specific and general risk mitigation) and/or to provide additional reward for the higher risks, as they are still deemed valid and applicable.

(10) The general risk mitigation approach, however, does not guarantee that the most beneficial and cost-efficient investments are put forward. For example, some investments may not be proposed by TSOs despite their higher value for society, because the regulatory frameworks treat all projects alike, while continuous technological advancements are likely to offer more cost-efficient solutions to reach the envisaged benefits/targets [6].

[1] Regarding electricity transmission, for two projects, both offshore, additional incentives were granted by the NRA with regard to high risks, e.g. cost overruns. For one project the request was rejected by the NRA because of lack of demonstration of higher risks.
[2] For some other project categories falling under the TEN-E Regulation, e.g. storage, hydrogen, the NRAs typically do not have any competence to grant incentives, and investments in such projects are often non-regulated.
[3] Regarding the reason for delays of PCs, please refer to ACER's annual consolidated reports on the progress of PCIs. The 2022 Report is available here:
https://acer.europa.eu/Publications/2022_ACER%20Report%20on%20progress%20of%20PCIs.pdf
[4] E.g. due to evolution of efficiency benchmarks, in particular when applying novel technologies with high risks of significant cost overruns.
[5] https://www.acer.europa.eu/Official_documents/Acts_of_the_Agency/Recommendations/ACER%20Recommendation%2003-2014.pdf
[6] E.g. where dynamic line-rating can mitigate the need for building new infrastructure.

(11) Therefore, in ACER's view, the focus on how to improve the incentives framework should be shifted from the project risk mitigation/compensation for TSOs to prioritising the identification of more cost-efficient, but currently "missing" solutions/projects.

(12) The needs identification introduced in the TEN-E Regulation (Articles 13 and 14) is an important step for setting the right goals for network development. It foresees that all relevant alternative network development options are considered and favours the most efficient solutions to be prioritised[7]. Given that from the collected information it seems that in many instances this step is not in place or not adequately developed in the national transmission planning frameworks, ACER sees a significant room for improvement by establishing or improving identification of the investment needs by TSOs and their regulatory scrutiny by NRAs.

(13) In this regard, NRAs should ensure that detailed technical studies for the identification of the investment needs are carried out by the TSOs, including at regional level, and that substantial public consultation takes place, and the necessary transparency for inclusive participation is ensured by making all relevant information (including the network and market datasets used for the studies) available to stakeholders.

(14) Furthermore, NRAs should establish and request TSOs to use a cost benefit analysis ('CBA') methodology at least for the assessment of high capital expenditure ('CAPEX') projects and pursue the monetisation (to the extent possible) of the most relevant project benefits (including, among others, market integration, variation of losses, security of supply and sustainability/climate benefits), in order to prioritise between proposed projects and among alternatives that could address the same need.

(15) NRAs should ensure that TSOs receive a fair and sufficient remuneration for their investments and face no counterincentives develop the network in the most efficient way, i.e. investment gaps are addressed by the most efficient (time- and cost-wise) projects. In this regard, it is important that TSOs do not face any bias towards specific solutions (e.g. preference for CAPEX-intensive solutions due to different remuneration scheme or business interests).

(16) ACER considers that CAPEX-bias (i.e. preference for CAPEX-intensive solutions due to different remuneration scheme or business interests) is currently a prominent issue in Europe[8], also taking into account that almost half of the Member States apply rate-of-return regulation for CAPEX, which is often combined with incentive regulation for operational expenditure ('OPEX'). Where NRAs conclude that CAPEX-bias is present in the regulatory framework, NRAs should primarily mitigate it with total-expenditure ('TOTEX') regulation.

(17) If the regulatory tools in place are insufficient to achieve that the investment gaps are addressed most efficiently (e.g. through low cost investments), NRAs should apply benefit-based incentives in a systematic way (i.e. not only upon request for individual projects), linked directly to

[7] Cf. recital (27) of Regulation (EU) 2022/869.
[8] ACER Position on incentivising smart investments to improve efficient use of electricity transmission assets: https://acer.europa.eu/Official_documents/Position_Papers/Position%20papers/Position%20Paper%20on%20infrastructure%20efficiency.pdf

measurable project benefits or major performance targets. ACER notes that these kinds of incentives already apply in several counties.

(18) Such incentives shall be set in a way to ensure the investment's value to the network users (i.e. decreasing the overall electricity costs), where NRAs may consider – under ex-ante defined and carefully set conditions – to share with the TSO part of the expected or measured benefits that the investment brings to society.

1. Introduction and background

(19) The European Green Deal is targeting a 55% reduction in greenhouse emissions by 2030 and climate neutrality by 2050, which foresees vast amount of investments in the energy networks in the coming years. This ambitious goal was strengthened by the 2022 REPowerEU targets, increasing the need to invest even further.

(20) ACER notes that the development of the necessary energy infrastructure strongly depends on the regulatory frameworks, including the applied risk mitigation methods and regulatory incentives for the transmission system operators ('TSO')[9].

(21) Pursuant to Article 58(f) of Directive (EU) 2019/944, Article 18(2) of Regulation (EU) 2019/943, Article 41(8) of Directive 2009/73/EC and Article 13(1) of Regulation (EC) No 715/2009, National Regulatory Authorities ('NRAs') have powers and duties to grant appropriate incentives to electricity and gas transmission system operators.

(22) The incentives and other regulatory measures of the national regulatory frameworks are typically applied on a network scale rather than for individual projects. They aim to provide an appropriate risk/revenue balance for developing the network and promote that the investments contribute to achieving various network objectives, such as increase of efficiencies, system performance, security of supply and market integration.

(23) Regulation (EU) 2022/869 ('the TEN-E Regulation') aims to facilitate the implementation of high benefit energy infrastructure projects for Europe by additional regulatory measures, including the possibility of granting project-specific incentives for high risk projects.

(24) More specifically, where a project promoter incurs higher risks for the development, construction, operation or maintenance of a Project of Common Interest ('PCI') falling under the competence

[9] Some transmission interconnectors owned by a natural or legal person which is separate, at least in terms of its legal form, from the system operators in whose systems that interconnector is to be built, may receive an exemption from certain requirements of the regulatory framework pursuant to Article 63(1) of Regulation (EU) 2019/943 or Article 36 of Directive 2009/73/EC. One prerequisite for any such exemption is, inter alia, that the level of risk attached to the investment at issue is such that the investment would not take place unless an exemption is granted. For these projects the regulatory incentives under Article 17 of Regulation (EU) 869/2022 shall not apply and they are out of the scope of this report.

of NRAs, when compared to the risks normally incurred by a comparable infrastructure project, appropriate incentives may be granted to that project.

(25) Pursuant to Article 17(5) of the TEN-E Regulation by 24 June 2023, taking due account of the information received from NRAs regarding their methodology and the criteria used to evaluate investments in energy infrastructure projects and the higher risks incurred by those projects[10], ACER shall facilitate the sharing of good practices and make recommendations in accordance with Article 6(2) of Regulation (EU) 2019/942 regarding project specific risk-based incentives on the basis of a benchmarking of best practice by national regulatory authorities as well as a common methodology to evaluate the incurred higher risks of investments.

(26) Further the Conclusions of the 2022 Copenhagen Infrastructure Forum invite NRAs to present how they accommodate incentives for investments in innovative, efficient and sustainable energy infrastructure. They ask ACER and NRAs to perform an assessment of current examples of good practices and lessons learnt on regulatory incentives and other relevant regulatory instruments that may be considered to facilitate the implementation of offshore infrastructure projects (and related onshore infrastructure reinforcements).

(27) Finally, in its Position Paper on Incentivising Smart Investments to Improve the Efficient Use of Electricity Transmission Assets (November 2021)[11], ACER signalled its aim to continue facilitating discussions on overcoming some identified hurdles, such as the CAPEX-bias and the general lack of appeal of low cost solutions along Europe's path to reach the Green Deal objectives as well as to share best practices.

(28) Pursuant to Article 17(4) of the TEN-E Regulation, the NRAs had to submit their methodologies and the criteria used to evaluate investments in electricity transmission, electricity storage, electricity smart grids, gas smart grids and hydrogen infrastructure projects and the higher risks incurred by them. Furthermore, ACER collected additional information from NRAs regarding national risk mitigation practices and the applied regulatory incentives. The data provision took place mainly in January 2023, therefore the provided information refers to the status as of that date, unless otherwise specified. The NRA submissions for electricity projects are provided in Annex 1.

(29) By end May 2023, NRAs of 25 Member States submitted information on electricity projects (including transmission, storage and smart grids). Malta informed ACER that it has no transmission network (nor an electricity TSO), while Cyprus did not provide a submission.

[10] Pursuant to Article 17(4) of the TEN-E Regulation, by 24 January 2023, each NRA shall submit to ACER its methodology and the criteria used to evaluate investments in energy infrastructure projects and the higher risks incurred by those projects, updated in view of latest legislative, policy, technological and market developments. Such methodology and criteria shall also expressly address the specific risks incurred by offshore grids for renewable energy and by projects, which, while having low capital expenditure, incur significant operating expenditure.

[11] https://acer.europa.eu/Official_documents/Position_Papers/Position%20papers/Position%20Paper%20on%20infrastructure%20efficiency.pdf

(30) For hydrogen, NRAs of 23 Member States, while for smart gas grids NRAs of 22 Member States provided some information. No submission was provided by the NRAs of Cyprus, Denmark, Ireland, Luxembourg and (for smart gas grids) Poland.

(31) The present Report builds on the findings and recommendations of the ACER Recommendation No 03/2014 on Incentives for Projects of Common Interest and on a Common Methodology for Risk Evaluation[12] and the ACER's Summary Report on Project Specific Risk-based Incentives (September 2018)[13].

(32) The remainder of the Report is structured as follows:

a) Chapter 3 reviews the scope of the regulatory competence and oversight of the energy infrastructure categories under the scope of Article 17 of the TEN-E Regulation, which are different from electricity transmission (i.e. electricity storage, electricity smart grids, gas smart grids and hydrogen infrastructure projects);

b) Chapter 4 investigates the existing regulatory framework for electricity transmission projects from different aspects:

i. Section 4.1 deals with the topic of the project-specific risk assessment. The Section recalls the previous ACER findings and recommendations on the categorisation and evaluation of project specific risks.

ii. Section 4.2 reviews the cases where project promoters claimed higher risks for a project and/or project specific incentives were deemed to be required by the NRA. The Section also includes those project specific incentives which were granted for particular projects not in relation to their risk profile, but for other reasons (e.g. facilitate the timely implementation of high benefit projects).

iii. Section 4.3 provides the main elements of how the systematic risks are assessed for regulated electricity transmission projects.

iv. Section 4.4 investigates the national regulatory frameworks for the identification and evaluation of individual investments, including for the purpose of prioritising them.

v. Section 4.5 presents how the national regulatory frameworks generally reimburse capital expenditures and operational costs, mitigate TSOs' risks and whether they provide incentives in order to implement the investments timely, cost-efficiently and/or to prioritise high benefit projects.

12 https://www.acer.europa.eu/Official_documents/Acts_of_the_Agency/Recommendations/ACER%20Recommendation%2003-2014.pdf

13 https://www.acer.europa.eu/Official_documents/Acts_of_the_Agency/Publication/ACER-summary-report-on-project-specific-risk-based-incentives_2018.pdf

c) Chapter 3 provides the ACER conclusions based on the findings of this Report.

d) Chapter 4 includes the ACER recommendations to NRAs.

2. Project categories different than electricity transmission

(33) The provision of Article 17(5) of the TEN-E Regulation regarding projects specific risk-based incentives encompasses the following energy infrastructure categories:

a) Electricity transmission

b) Electricity storage

c) Smart electricity grids

d) Smart gas grids

e) Hydrogen infrastructure

(34) For projects under these infrastructure categories, in order for Article 17(5) to apply, several conditions need to be met, including that the project is under the competence of an NRA.[14]

(35) ACER notes that most electricity transmission projects are regulated. As described below in more detail, the other project categories, with few exceptions, at national level either fall under the category of the regular regulated transmission assets without any differentiation (e.g. the transmission-related projects which could qualify as electricity or gas smart grids under the TEN-E Regulation are treated the same as other electricity or gas TSO assets) or they are not (or not yet) under NRA's regulatory oversight (e.g. non-TSO energy storage and hydrogen infrastructure projects).

(36) Furthermore, except for two electricity transmission projects, no project specific risk-based incentives have been granted by the NRAs during the past ten years for the concerned energy infrastructure categories listed in Recital (33)[15].

(37) Therefore, ACER deems that for non-TSO energy storage and hydrogen infrastructure project categories, in view of the lack of sufficient regulatory practices, it is premature to benchmark best practices and provide any targeted recommendations regarding risk evaluation and provision of

[14] Other conditions: the project has to be included in the Union list of PCIs, project promoter incurs higher risks for the development, construction, operation or maintenance, the project did not receive any exemption from the relevant provisions of the electricity or gas market regulation pursuant to Article 36 of Directive 2009/73/EC and Article 17 of Regulation (EC) No 714/2009.

[15] Two additional requests for project specific incentives were submitted by the project promoters (one for electricity transmission and one for energy storage), but the requests were rejected in lack of demonstration of the higher risks or due to other ineligibility, as described later in this Report.

project specific risk-based incentives. ACER underlines that unless explicitly stated otherwise, the corresponding recommendations in this Report refer to regulated electricity transmission projects; by analogy they apply to other energy infrastructure project categories under Article 17(5) as long as they are treated the same way (i.e. without any differentiation) by the national regulatory frameworks.

Electricity storage:

(38) TSOs can own, develop, manage or operate energy storage assets (e.g. pumped hydro energy storage, batteries, etc.) only based on a derogation[16]. Non-TSO storage facilities connected to the transmission grid were reported to be subject to regulatory oversight only in four Member States (GR, IE, PL, RO), but even in these instances the regulatory oversight is limited to licencing, checking compliance with market and network codes and/or running tenders.

(39) In none of the Member States non-TSO storage facilities are reported to be generally subject to risk evaluation or investment evaluation (in view of a lack of allowed revenues and network plan) or subject to any regulatory approval for cost recovery via regulated tariffs. In all Member States, storage investment decisions are either left fully to business interest (of the project promoters) or there is no storage facility connected to the transmission grid.

(40) Only in one country (LT), there is a storage operator which is regulated, but only on a temporary and exceptional basis until 2025 related to the Baltic synchronisation. The Lithuanian NRA reported that the project promoter of this regulated electricity storage facility applied for additional incentives due to higher risks: The storage operator claimed for WACC premium, claiming risks related to the new technology. However, the claim was rejected due to the fact, that operator was appointed by the law, which also defined its technology and its cost recovery.

Smart electricity grids:

(41) None of the NRAs reported any specific regulatory framework (or major difference compared to electricity transmission or distribution investments) for smart electricity grids with regard to their investment evaluation, risk evaluation and/or remuneration. According to the reported information, as long as they are assets of the regulated TSOs/DSOs, investments in smart grid projects are treated the same way as any other transmission/distribution investments.

(42) At the same time, ACER notes that at least three Member States (FR, PT, SI) provide some regulatory incentives explicitly targeting smart electricity grids, such as increase of allowed expenditures for some cost categories, including ex-post adjustments and monetary reward/penalty schemes. These practices are listed in Table 1 below. In additional Member States, the regulatory frameworks may approve a specific budget (or provide other regulatory measures) to support research and development projects, including those related to digitalisation and smart grids.

[16] Cf. Article 54(2) of Directive (EU) 2019/944

Table 1: Regulatory incentives targeting explicitly smart electricity grids

Country	Regulatory incentives
FR	To foster innovation in smart grid projects, the network tariff includes a “smart grid counter”, through which the TSO (RTE) is authorised to request, once per year, coverage of OPEX or capital expenses relating to the deployment of smart grid technologies not included in the tariff OPEX trajectory or in the capital charges trajectory for information systems.
PT	Since 2019, an output-based incentive is in place in distribution, which aims to lead the DSO to deliver to consumers value added services enabled by smart grids. This incentive awards DSOs with a fixed annual amount (for a fixed number of years) per low voltage supply point that delivers a certain list of smart grid services to consumers. Additionally, the NRA is required by national law to define a specific regulatory framework for pilot projects, which may allow specific derogations and approval of costs associated with smart grid projects.
SI	The NRA provides a performance-based incentive for efficient smart grid investments of TSOs/DSOs, which are linked to monitoring of a series of Key Performance Indicators (‘KPIs’) in (some of) the following areas: exploitation of flexibility; network capacity utilisation; increasing transmission capacity; hosting capacity and the level of integration of distributed elements; voltage quality; grid losses; asset lifetime; forecast accuracy; provision of real-time information to interested stakeholders; openness to third-party innovation; and environmental impacts. Two types of KPIs are used to monitor the performance of smart grid investments: key preparedness indicators and key performance indicators. An individual KPI is defined as a weighted composite of indicators. The assessment of the performance of investments on the basis of the KPIs may be conditional on the achievement of an appropriate level of each KPI or individual preparedness indicator. Based on the KPIs of each type, an umbrella preparedness KPI and an umbrella efficiency KPI is calculated. The principles of performance-based regulation of smart grid investments are: publication of performance indicators in the context of the development plans of the system operators; a functional link between the performance of smart grid investments and the eligible costs of the DSO or the TSO; definition of minimum standards for the preparedness of the distribution and transmission networks. Performance based regulation for smart grid investments represents a feedback management process, where the NRA influences the process by adjusting the eligible costs in such a way that it seeks to maximise the level of efficiency. This is a novel incentive scheme (introduced for Regulatory Period 2023/2024-2028). Optimizations and possible upgrades with potentially harmonized KPIs on EU level are expected. Since 2015 there is also a project-oriented incentive scheme for qualified specific smart grid projects with the aim of enabling the introduction of new technologies. Appropriate restrictions are considered in order to prevent multiple financial incentives for providing the same benefits.

Smart gas grids:

(43) In most Member States, smart gas grids are not defined or they fall under the competence of NRAs the same way (i.e. without any differentiation) as any other transmission infrastructure projects promoted by the gas TSO. In none of the Member States a dedicated regulatory framework for smart gas grids (or some regulatory incentives explicitly targeting them) was identified. (For more details, please refer to Table 2)

Table 2: Treatment of smart gas grids in each national regulatory framework

Country	Description of treatment of smart gas grids
AT	• No special regulatory framework in place for smart gas grids. These projects are treated the same way as other TSO projects; • Revenue Cap regulation for CAPEX and OPEX (4-year regulatory period)[17]
BE	• Infrastructure investments related to gases compatible with natural gas (e.g. biomethane) are considered within the existing legal framework applicable for natural gas and basically treated the same and blended in the same infrastructure; • Revenue Cap regulation for CAPEX and OPEX (4-year regulatory period); • Link to investment and risk evaluation methodology[18]
BG	• No NRA competence was reported
HR	• There is no special regulatory framework for smart gas grids. These projects are treated the same way as other TSO projects; • Revenue Cap regulation for CAPEX and OPEX (5-year regulatory period).
CZ	• No special treatment for smart gas grids – evaluation as standard gas investments by NRA • Revenue Cap regulation[19] for CAPEX and OPEX (5-year regulatory period)[20]; • Link to investment and risk evaluation methodology[21]
EE	• No NRA competence was reported
FI	• Revenue cap regulation for CAPEX and OPEX (8-year regulatory period)
FR	• General regulatory framework of gas TSO investments would apply, but no precedent yet.
DE	• If the assets are part of the regulated gas transmission or distribution network the respective NRA-competence is given, otherwise there is no NRA competence. • Revenue Cap regulation[22] for CAPEX and OPEX (5-year regulatory period), CAPM model[23] • Link to investment and risk evaluation methodology[24]

[17] AT:https://www.e-control.at/documents/1785851/1811582/E-Control_Cost_Methodology_2021_2024_EN.pdf/81ad7664-3c27-9360-5283-81a39e3a815e?t=1596794285387

[18] BE: https://www.creg.be/fr/publications/autres-z1110/12

[19] CZ: https://www.eru.cz/sites/default/files/obsah/prilohy/price-control-principles-2021-2025.pdf (CAPEX treatment in chapter 4).

[20] CZ: On the basis of the Energy Act 458/2000 the regulatory period in the Czech Republic is set to at least five consecutive years.

[21] CZ: https://www.eru.cz/metodika-kriteria-pro-hodnoceni-elektroenergetickych-plynarenskych-infrastrukturnich-projek (in Czech)

[22] DE: The revenue caps for network operators are set for a five-year regulatory period. Each cap is composed of permanently non-controllable costs, temporarily non-controllable costs, controllable costs (applying a distribution factor for reducing inefficiencies), general inflation relative to the base year and a general sectoral productivity factor, a CAPEX in-period top-up to take account of the cost of capital for investments after the base year, and volatile costs. The difference between the allowed revenue and the development of actual volumes over the year is entered into a regulatory account.

[23] DE: As per the regulatory accounting rules, the equity financed RAB of a network operator is multiplied with an equity return. The equity return consists of a risk-free rate, an equity risk premium and taxes. In brief, the equity risk premium consists of a market risk premium multiplied with a beta plus a correction. The market risk premium reflects the premium on investments in a fully diversified portfolio. The beta is the proxy for company specific risks. The methodology applied is the CAPM. The same methodology applies for electricity and gas networks at transmission and distribution level. The regulatory instruments "investment measure" and "CAPEX top-up" ensure that network operators can reflect their investments in the revenue cap during the regulatory period in order to ensure a timely cost recovery. Moreover, fixed return on equity, currently (4th regulatory period) 5.07% pre-tax. The maximum amount of equity is capped at 40%.

[24] DE: https://www.bundesnetzagentur.de/DE/Beschlusskammern/BK04/BK4_91_Weiteres/Anreize_Art13_VO_EU_347-2013/Anreize_gem_Artikel_13_der_Verordnung_EU_347-2013_node.html

Country	Description of treatment of smart gas grids
GR	• The NRA is required by the national law to evaluate the future investments in smart gas grids and express its opinion to the Hellenic Ministry of Environment and Energy, which then decides on the approval or not of the aforementioned investments; • Cost-plus regulation[25] for CAPEX and OPEX (4-year regulatory period); • The NRA is in the process of adopting incentives for innovative projects (may include smart gas grids and hydrogen projects).
HU	• Smart gas grids are regulated by the NRA insofar as they are parts of the regular gas networks. No separate regulatory framework has been developed for smart gas grids. • Rate-of-Return regulation for CAPEX[26] and Revenue Cap regulation for OPEX[27] (4-year regulatory period)
IT	• The NRA introduced a specific grant mechanism aimed at supporting innovation in the field of natural gas[28]; • Ordinary tariff regulation is applied. No specific regulation for smart gas grids (6 year-regulatory period)[29]; • Link to investment and risk evaluation methodology[30]
LV	• Revenue Cap regulation for OPEX (3 years regulatory period)[31]; • Link to regulatory incentives applied[32]; • Link to investment and risk evaluation methodology[33]
LT	• Incentive regulation (with elements of rate of return, i.e. hybrid) for CAPEX and Revenue Cap regulation for OPEX (5-year regulatory period) • Link to the methodology for assessing additional regulatory incentives and risks of Investment projects[34] • Link to the Rules on the procedure for evaluation and appraisal of investments of natural gas, electricity, liquefied petroleum gas companies[35]
MT	• The NRA has the duty to regulate, monitor and keep under review all practices, operations and activities relating to energy services and resources in Malta, and it has also the duty to

[25] GR: The current Regulation is cost-plus for both OPEX and CAPEX, but this Regulation is under revision in order to move to an incentive regulation regarding OPEX (Revenue-Cap methodology for OPEX).
OPEX of each regulated service, for each year of the regulatory period, are the reasonable costs for the operation and maintenance of the gas system in an efficient, safe, cost-effective, reliable and rewarding manner for the users.
[26] HU: The NRA determines the justified rate of WACC, which is then applied to the regulatory asset base (the value of which is determined during the periodic cost and asset reviews).
[27] HU: A CPI-X method incentive regulation is applied to operating costs during the regulatory period. The justified level of operating costs is determined every four year, by the cost and asset review undertaken before the regulatory period.
[28] IT: With decision 404/2022/R/gas, the NRA introduced a grant scheme devoted to selected pilot projects, aimed at easing the integration of renewable energy sources, reducing gas emissions, and easing the energy transition falling under the following categories:
1. Methods and instruments for the optimal management of networks;
2. Innovative usage of existing networks;
3. Technological/management innovation of networks;
To get access to the grant those entitled (entities subject to the NRA tariff regulation of natural gas infrastructures) must fill in an application by 15 April 2023. After an evaluation process, the NRA selects the projects deserving to get access to the grant and publishes the list of the beneficiary entities on its website.
[29] IT: Distribution regulatory period covers the years 2020-2025
[30] IT: https://arera.it/it/docs/22/404-22.htm
[31] LV: 3 years for natural gas TSO and 2-5 years to DSO.
[32] LV: https://likumi.lv/ta/id/335113-kapitala-izmaksu-uzskaites-un-aprekinasanas-metodika
[33] LV: https://www.sprk.gov.lv/sites/default/files/editor/Ener%C4%A3%C4%93tikas%20tarifi_Dabasg%C4%81ze_metodolo%C4%A3ija%20un%20krit%C4%93riji%20ieguld%C4%ABju%20nov%C4%93rt%C4%93%C5%A1anai%20elektroener%C4%A3ijas%20un%20g%C4%81zes%20infrastrukt%C5%ABras%20projektos.pdf
[34] LT: https://www.e-tar.lt/portal/lt/legalAct/fa72a0404b3811eb8d9fe110e148c770
[35] LT: https://www.e-tar.lt/portal/lt/legalAct/TAR.930473CEC480/asr

Country	Description of treatment of smart gas grids
	evaluate investments requests and granting licence, permit or other authorisation about type of projects abovementioned. • No specific regulatory framework in place for smart gas grids. • Link to investment and risk evaluation methodology[36]
NL	• The NRA does not use the term "smart gas grids". It regulates gas networks as a whole. • Regulatory framework for CAPEX and OPEX: a method in between Cost-plus and Revenue cap[37] (Regulatory period varies between 3 and 5 years)
PT	• No special regulatory framework is in place for smart gas grids; • Rate of Return regulation for CAPEX and Price Cap regulation for OPEX[38] (4-year regulatory period)[39]
RO	• No specific regulatory framework in place for smart gas grids; • Link to investment and risk evaluation methodology[40]
SK	• Cost-plus regulation for CAPEX and Revenue Cap regulation for OPEX (5-year regulatory period); • Regulatory incentives for smart gas grids are under development; • Link to investment and risk evaluation methodology[41]
SI	• There is no specific regulatory framework for incentives for smart gas grids; • Revenue Cap regulation for CAPEX and OPEX[42]; • Link to investment and risk evaluation methodology[43]
ES	• NRA is competent as long as the asset is integrated in the natural gas network (the same treatment as for gas transmission); • Regulatory framework for CAPEX and OPEX (6-year regulatory period)
SE	• There is no specific regulation regarding smart gas grids. • Regarding gas grids generally there is a revenue cap regulation for CAPEX and OPEX (4-year regulatory period)

Hydrogen infrastructure projects:

(44) ACER notes that in only five Member States (DE, LT, MT, PT, RO), NRAs reported that they have some competence (e.g. evaluation and/or tariff approval) for hydrogen infrastructure, but even in these cases it is often an exception or limited to PCIs. In the remaining Member States, NRAs have no competence over hydrogen infrastructure or the legal basis giving competence over hydrogen infrastructure to NRAs has not been established yet. In some Member States the legislative framework on how to organise the hydrogen market and system development is under discussion. (For more details, please refer to Table 3 and Table 4)

[36] MT: https://downloads.rews.org.mt/files/3230b4bb-00cc-4149-bff4-2e53e1fb1181_9d4f35ce-a520-4ad9-a7ee-fc1d0ba01ec2.pdf
[37] NL: Formally TOTEX revenue cap regulation for the TSO and TOTEX price cap regulation for DSO's are used. In practice, most of the CAPEX for the TSO is calculated in such a way that it closely resembles cost-plus regulation because most costs are reconciled in annual tariff decisions.
[38] PT: Currently, there are no H2 and no smart gas grid investments
[39] PT: Before 2020, the regulatory period was 3 years
[40] RO: https://www.anre.ro/ro/gaze-naturale/legislatie/metodologii-tarifare/metodologii-si-criterii
[41] SK: https://www.slov-lex.sk/pravne-predpisy/SK/ZZ/2022/451/ (method described mainly in Article 6)
[42] SI: WACC on average asset value.
[43] SI: https://www.agen-rs.si/web/en/projekti-skupnega-interesa1

Table 3. NRA competence over hydrogen infrastructure

Country	Description of NRA competence / responsibility
DE	H2 networks are not generally regulated. However, according to the national law the network operators may choose to be subject to regulation by declaration towards the NRA (opt-in declaration). In case that the legal requirements are fulfilled, the NRA determines that the network of a certain operator is subject to regulation. The NRA competence covers unbundling, network connection and access, cost regulation, needs examination and network development. Once a H2 network operator is subject to regulation, its existing and any future infrastructure will be subject to a needs assessment. The focus is on the use of the infrastructure, i.e., on the connection petitioners, possible feed-in and feed-out. Only the hydrogen grid requirements are checked. An evaluation of investment does not take place. These plans also have no binding character. Concerning hydrogen storage facilities, operators of hydrogen storage facilities may declare to the NRA that the relevant provisions shall apply mutatis mutandis to access to their hydrogen storage facilities. Regulated hydrogen network operators are granted a fixed return on equity of 9% pre-tax until 31.12.2027 on their operationally necessary equity. Regulated hydrogen network operators can apply a specific (individual) asset life as regarded suitable when calculating the depreciation.
LT	NRA might approve hydrogen projects only if they are implemented by regulated company and is classified as innovation (sandbox) projects. Moreover, only 50% of CAPEX might be included into regulated prices and the other 50% should be covered by the company. Currently, there are no H2 investments.
MT	The NRA has the duty to regulate, monitor and keep under review all practices, operations and activities relating to energy services and resources in Malta, and it has also the duty to evaluate investments requests and grant licence, permit or other authorisation. No specific regulatory framework in place for hydrogen projects.
PT	The NRA has a non-binding competence on the evaluation of investments in hydrogen projects for the purpose of inclusion in the Union List of PCIs. The Portuguese Government has the binding decision. Once a project is approved by the Government, the NRA considers its cost for the tariff calculation process. Rate of Return regulation for CAPEX and Price Cap regulation for OPEX (4-year regulatory period). Currently, there are no hydrogen investments.
RO	The NRA approves the regulated tariffs and their methodologies for the transmission system operator, the distribution system operator and the hydrogen terminal operator.[44]

[44] https://www.anre.ro/ro/gaze-naturale/legislatie/metodologii-tarifare/metodologii-si-criterii

Table 4: Treatment of hydrogen infrastructure in each national regulatory framework (in countries with no NRA competence over hydrogen infrastructure)

Country	Description of treatment of H2 infrastructure
AT	• The NRA is not responsible for regulating the H2 infrastructure. • The legal basis is not yet established, but the discussions on principles started.
BE	• H2 investments (transmission, terminal, storage) currently non-regulated activities but a national legislative work is underway to provide a legal framework for H2 market, system development and role to the NRA.
BG	• No NRA competence was reported
CZ	• The NRA is not responsible for regulating the H2 infrastructure. • Implementation of H2 in the national legislation by the Ministry of Industry and Trade is ongoing.
EE	• No NRA competence was reported
HR	• "Croatian Strategy for H2 until year 2050" foresees H2 as a new energy carrier in the transport sector and to build an adequate infrastructure for the production, distribution and supply of hydrogen. • NRA has no competence yet regarding H2 infrastructure. Legislative work will be commenced.
FI	• H2 infrastructure is not existing in Finland. • There is no specific national regulation on H2 or NRA role on the matter.
FR	• There is currently no legal ground for the competence of the NRA (CRE) on H2 infrastructure.
GR	• H2 projects do not fall under the competence of the NRA for the time being, given the fact that the Greek Law has no provisions for renewable gases such as Hydrogen yet[45].
HU	• The NRA is not responsible for regulating the H2 infrastructure.
IT	• The NRA is not responsible for regulating the H2 infrastructure.
LV	• The NRA is not responsible for regulating the H2 infrastructure. • There is no H2 regulation yet.
NL	• The NRA is not responsible for regulating the H2 infrastructure.
PL	• The regulatory framework for hydrogen infrastructure projects is still under establishment, and the role of the NRA is not defined yet
SK	• NRA with competence to set up: Method to set up simulation of the regulated entity´s approved investment in assets used for (among others): connecting gas producers and their equipment using hydrogen technologies, conversion of gas infrastructure to use gases from carbon-free sources, for example H2, biomethane. • Regulatory framework is not defined for CAPEX, Rate-of-return and Revenue Cap regulation for OPEX (5 year-regulatory period); • Regulatory incentives are case by case, with applying the method defined under the regulatory period; • Link to investment and risk evaluation methodology[46]
SI	• A relevant legislation have not yet been adopted, so the NRA does not have the power to regulate hydrogen infrastructure.
ES	• The NRA is not responsible for regulating the H2 infrastructure. • Ministry of Ecological Transition and Demographic Challenge has certain responsibilities on H2.
SE	• The NRA is not responsible for regulating the H2 infrastructure. • There is no specific national regulation on H2.

[45] GR: In case there will be provision by Greek law for H2 infrastructure, Cost-plus regulation will be applied both for CAPEX and OPEX

[46] SK: https://www.slov-lex.sk/pravne-predpisy/SK/ZZ/2022/451/

3. Electricity transmission

3.1. Project-specific risk assessment

(45) Recital (49) of the TEN-E Regulation considers that investments in some types of PCI are likely to incur higher risks than similar projects located within one Member State for example:

a) cross-border projects;

b) innovative transmission technologies for electricity allowing for large-scale integration of renewable energy, of distributed energy resources or of demand response in interconnected networks, and energy technology and digitalisation projects; and

c) offshore grids for renewable energy, which serve the dual functionality of electricity interconnectors and connecting renewable offshore generation projects, are likely to incur higher risks than comparable onshore infrastructure projects, due to their intrinsic connection to generation assets which brings regulatory risks, financing risks such as the need for anticipatory investments, market risks and risks pertaining to the use of new innovative technologies.

(46) Symmetrically, it may be the case that certain risks for a PCI are lower than the risks of a non-PCI (and non cross-border) comparable project. For example, this may be the case in instances where the priority linked to the PCI status (and the streamlined permitting procedure ensured by the TEN-E Regulation) increases the acceptance of the project and (consequently) the project planning and permitting procedures are facilitated.

(47) Similar to its findings in 2014, ACER notes that NRAs do not generally assess the specific risks of individual investments or set any particular criteria for granting project specific incentives or have any standard practice to identify a comparable investment for the assessment of higher risks. The general approach adopted by NRAs (see in Section 4.3. below) is consistent with the hypothesis that different projects belonging to the transmission activity have the level of systematic risk of the overall transmission activity and that the non-systematic (diversifiable) risk can be eliminated or significantly reduced by the TSO or other project promoter through diversification.

(48) As long as offshore electricity transmission projects are regulated, no offshore project-specific regulatory risks, financing risks and market risks would actually arise or – in other terms – the same level of risk would generally apply to offshore and to onshore projects.

(49) ACER considers that the same finding applies for TSO's offshore anticipatory investments[47]. As described in more detail in Section 4.5 below, in the vast majority of the Member States once the investment is positively assessed by the NRA (including that the risks are deemed acceptable for

[47] For the purpose of this Report, the term "anticipatory investments" refer to investments that are risky for society because they may turn out be underused, at least for some years, until developments on the generation side.

the society), the costs will be reimbursed despite the actual utilisation of the asset (i.e. volume risk is largely mitigated), in this regard offshore anticipatory investments do not generally entail higher risks for the TSOs compared to other projects.

(50) ACER underlines that given the specific features of the regulatory system in place in each Member State, the general risk mitigation measures provided by the national regulatory framework and the additionally available measures for mitigating the risk faced by particular project promoters may be different. Therefore, the application of the common risk identification and risk assessment methodology for the same project in different Member States may result in different conclusions on the need for additional incentives. Instead of providing such conclusions, the methodology should encourage a reasonable and transparent evaluation of the risk.

(51) In order to appropriately assess the risks attached to a project – e.g. in order to decide on the need for any project specific incentives due to higher risks – ACER in its Recommendation No 03/2014 already set out a common methodology for risk identification and risk assessment. This methodology includes a step-wise risk-evaluation approach under which NRAs shall (further) analyse the specific risk incurred by the project promoters, the risk mitigation measures taken and the justification of this risk profile in view of the net positive benefit provided by the project, when compared to a lower-risk alternative. This common methodology is still deemed by ACER valid and applicable.

(52) The common methodology for risk identification and risk assessment proposed by ACER includes the 7 steps. In this report, ACER provides a summary and updates of these steps below. For more information on each of these steps please refer to ACER Recommendation No 03/2014 (p. 4-7).

a) Step 1: Availability of information on project risks; Project promoters, as the best informed parties about their project's features and aspects, should primarily carry out the risk evaluation and submit to the concerned NRAs all the necessary information for the proper assessment of the actual risk exposure. Specifically, project promoters should provide NRAs with all the elements required to assess whether the incurred risks are higher than those of a comparable project, as well as substantiate how and to what extent the alleged risk could negatively impact the project promoters. NRAs may request additional information from project promoters when they consider it necessary for properly assessing their risk exposure.

b) Step 2: Identification of the nature of the risk from a regulatory point of view; The evaluation of the risk of the project should be carried out by each concerned NRA, in relation to the respective national regulatory framework and, jointly by all the concerned NRAs, with regard to risks linked to any necessary cross-border coordination. NRAs should use a harmonised categorisation for the assessment of risks as described in recital (90) of this Report.

c) Step 3: Risk-mitigation measures by the project promoters; In all cases, and regardless of the nature of the risk, NRAs should assess to what extent the risk can be reduced by the project promoters with reasonable effort through appropriate measures (e.g. penalty agreements with project partners and commercial instruments, such as insurance and hedging), including diversification.

d) Step 4: Assessment of systematic risk and definition of cost of capital; NRAs should assess – also based on the information which is to be provided by project promoters – to what extent the risk is already reflected in the cost of capital that the project promoter is allowed to recover via tariffs. If the allowed cost of capital has been determined based on the Capital Asset Pricing Model ('CAPM') approach, NRAs should examine to what extent the risk constitutes a systematic risk that is already covered by the allowed cost of capital, taking into account that – in the CAPM approach – the non-systematic risk should not be rewarded, as it can be diversified away by the project promoter (see step 3).

e) Step 5: Risk-mitigation measures already applied by NRAs; NRAs should assess if there is a regulatory instrument that is already in place that mitigates the risk fully or partially.

f) Step 6: Risk quantification; NRAs, as far as possible, should assess the information provided by the project promoters and the risk exposure in terms of (potential) higher costs or lower revenue for the project promoters. The consolidated risk approach of investigating the potential impact of an event and the probability of its occurrence, as well as the assessment of the magnitude of the risk by multiplying the former two parameters, should be pursued. When quantification is not possible or appropriate, a qualitative comparison of risk level compared to another comparable project should be carried out.

g) Step 7: Comparable project; NRAs should assess to what extent the risk is higher for the project promoters than the risk of a comparable project and to what extent it is justifiable when compared to a lower-risk alternative in view of the net positive impact provided by the project. The identification of a comparable project should be conducted on a case-by-case basis considering projects with comparable features (for instance regarding the technology, capacity, voltage level, structure of capital and operational expenditures, etc.) that are implemented in the Member States where the project under analysis is located. In general, the risk of the project component located in one country should be compared to projects in the same country, as the risk for the project promoter also depends on the regulatory system of the country. This should not preclude NRAs from taking into account relevant experience from other Member States, especially where projects with comparable features do not exist in the same country. In such cases, projects should always be reviewed in the light of the regulatory system of the country in which the project promoter plans to invest.

3.2. Project-specific incentives (risk-based or benefit-based)

(53) ACER finds that in the vast majority (over 80%, 21 out of 25) of the Member States the NRA has received no request for project specific incentives for any electricity transmission project over the past 10 years. This means that these NRAs did not grant any project specific incentive due to higher risks to any PCI (as foreseen under the previous version of the TEN-E regulation) or other (non-PCI) projects, neither had they granted any benefit-based incentives on an individual project basis.

(54) In the remaining four Member States, in total for five projects the NRA received request for project specific incentives. The national practices regarding the treatment of these five requests are presented below. Out of them, one request was rejected by the NRA (because of lack of demonstration of higher risks) for two projects (both offshore) the additional incentives were

granted with regard to high risks, for two projects (one offshore and one onshore) the incentives were granted with regard to high benefits. The applied project specific incentives, among others, include WACC adders, increase of revenue cap, cost recognition before commissioning and pass-through some (efficient) costs.

(55) The Italian NRA informed that it developed and applied priority-based incentives to a wide set of projects in the form of "WACC adder" for the period 2012-2015 and for the period 2016-2019, at a reduced rate of 1% additional WACC for 12 years, as a transition measure before the complete phase-out of priority premia. The Italian NRA also applied risk-based incentives in the period 2017-2022 to non-PCI projects, which led four projects to receive a specific treatment of investment during construction (allowing a slightly higher return, which was in between the regular return for investment during construction and the regular WACC) due to long construction times (more than 3 years). These measures are not described in more detail among the practices below because they are deemed as systematic and not "individual-project" measures.

(56) The Irish NRA informed that for 2 additional projects (both are offshore interconnections with Ireland) the incentives framework is individually designed in lack of standard framework for them for the time being[48]: In one instance (interconnection with United Kingdom)[49], the project has been granted a Cap & Floor regulatory regime (revenues are capped, but they are also underpinned via network tariffs subject to set availability targets)[50], while in the other instance (interconnection with France)[51] the project's remuneration is fully underpinned via network tariffs and introduces a delivery incentive mechanism which covers both cost and time. In lack of standard framework, these incentives are not considered as additional project specific incentives and thus not described in more detail among the practices below.

NATIONAL PRACTICES: Project specific incentives (risk-based or benefit-based)

THE NETHERLANDS
PCI 1.5 Denmark — Netherlands interconnection between Endrup (DK) and Eemshaven (NL) [currently known as "COBRA cable"] – RISK RELATED
Year of claim/incentive: 2015 Claimed risks: HVDC subsea cable with specific risks caused by challenges of subsea environment. Accepted risks: The decision is based on the analysis of the claimed risk by the project promoter and other comparable subsea projects.

[48] The Irish NRA indicated that the wider incentive framework for interconnectors will be developed in due course.
[49] PCI 1.9.1 Ireland — United Kingdom interconnection between Wexford (IE) and Pembroke, Wales (UK) ["Greenlink"]
[50] The Cap & Floor regime builds upon the NRA decisions that construction and operation of the Greenlink electricity interconnector would be in the public interest (CRU18216); and a Cap & Floor regulatory regime covering half the project's costs and revenues would be the most appropriate regulatory treatment (CRU20171). Further details on the regime's function and how it allocates risks associated with the project between the project promoter and the Irish electricity customers over the project's lifetime is provided here:https://www.cru.ie/publications/26176/
[51] PCI 1.6: France — Ireland interconnection between La Martyre (FR) and Great Island or Knockraha (IE) ["Celtic Interconnector"]

Financing: The cable is financed through transmission tariffs. Risk-mitigating incentives granted / other risk mitigation measures: Ex-post adjustments, e.g. when costs are proven to be higher than reasonably could be estimated; (higher) allowance for operational expenditures or other cost categories “When the costs turn out to be higher than expected, but still efficient, they will not be taken into account for the assessment or cost comparison. In addition to that, the COBRA cable will not be part of the benchmark study for the first 10 years after commissioning. Instead, a project specific cost assessment will be used to determine efficient costs during these years. For the operational costs of the Cobra cable during this 10 year period, a fixed compensation of 3.4% is applied for the offshore part of the total efficient investment expenditure determined on the basis of the project specific cost assessment.” (COBRA receives 3.4% of the total efficient costs as a compensation for the operational expenditure. 50% of the difference between this lump sum compensation and the realised operational expenditure will be settled ex-post. This is due to the higher risks the COBRA cable faces. The 3.4% is only applied for the operational costs of the offshore part of the COBRA cable, so it needs to be seen separately from the general 1% lump sum for operational expenditure (applied to the onshore part), which is equally applied to all investments of TenneT.) In addition to the incentives, the TSO itself presents in its request the technical risk mitigation measures it is adopting for this project.
PCI 2.12 Germany — Netherlands interconnection between Niederrhein (DE) and Doetinchem (NL) – RISK RELATED (APPLICATION REJECTED)
Year of claim/incentive: 2015 Claimed risks: This project, as a PCI, was eligible to apply for incentives within the scope of Article 13 of Regulation (EU) No 347/2013. However, the project promoter did not demonstrate that the project faces higher risks than a comparable infrastructure project. The NRA therefore did not grant project-specific risk-based incentives under Article 13. Financing: the project is financed through transmission tariffs. Other information: In its decision, the NRA included a number of regulatory measures outside the scope of Article 13, in order to account for the obligation to use a specific (more expensive) type of masts (so-called “WinTrack masts)” imposed on the project promoter by the Dutch government. With respect to the international benchmarking of costs which is part of the national regulatory framework, the NRA excluded the additional costs of these non-standard masts (compared to regular masts) because these additional costs are the result of a government decision beyond the control of the project promoter. The NRA accordingly decided that these higher costs will be remunerated, as far as they are deemed as efficiently incurred. For the operational expenditures, a lump sum remuneration was granted, in line with the regular practice for all projects labelled as “exceptional expansion investment” (“bijzondere uitbreidingsinvesteringen”).

BELGIUM
Modular Offshore Grid (non-PCI) – RISK RELATED (APPLICATION PARTLY ACCEPTED)
Year of claim/incentive: 2018 Claimed risks: Risk of time overruns; Risks of cost overruns, Liquidity risk; Risks due to contractors: Available offers for cables; Risk of stranded assets: Dismantling of the offshore turbines; Continuous modifications of the project; delays or bad quality of the Seabed Survey; Contractors quality of work. Accepted risks: Risk of time overruns; Risks of cost overruns: Offshore maintenance costs; Risk of stranded assets: Dismantling of the offshore turbines; Continuous modifications of the project; Contractors’ quality of work. In its decision, the NRA concluded that most of the claimed risks are actually borne by the grids users or could be mitigated through additional measures (governance team, client representation and contractual clauses regarding quality and delays). The accepted risks were valorised based on a Monte Carlo methodology. Risk-mitigating incentives granted / other risk mitigation measures: Additional risk premium of 1.4% on the capital invested in the project during 30 years; Reduced depreciation period from 50 to 30 years; Pass-through for costs from additional specific activities under specific conditions (i.e. costs from contractors after insurance’s intervention); Pass-through of provisions for dismantling costs; Pass-through of penalties due to offshore wind parks if not under the TSO’s responsibility.

GREECE
ARIADNE INTERCONNECTION: Crete – Attica Interconnection (non-PCI) – BENEFIT-BASED
The estimated year for the completion of the interconnection and the operation of subsea line is 2024/2025[52]. Based on the methodology being in place when the project was approved (Decision 340/2014, article 11) a premium rate of return was approved to be provided, in addition to the rate of return (WACC), because the project was characterised as 'Project of Major Importance' in the national network development plan. With a subsequent decision, the premium return was set 1%. The premium rate of return will provided from the electrification of the project and up to the 12th year from the scheduled year of electrification in the national network development plan, where it was characterised as a Project of Major Importance**.** Project specific incentives (WACC adders / additional return on capital) granted due to high positive benefits (and not due to higher risks).

LUXEMBOURG
PCI Cluster 2.3 – Belgium Luxembourg capacity increase at the BE/LU border: 2.3.1 Coordinated installation and operation of a phase-shift transformer in Schifflange (LU) – BENEFIT-BASED
Year of claim/incentive: 2013 Project incentives: The tariff methodology 2013-2016 foresaw a WACC adder of 0.6% for a duration of 10 years on cross border interconnection projects that significantly improve security of supply. The project received this WACC-adder.

3.3. General risk assessment (systematic risk)

(57) Each national regulatory framework typically provides the same return to all electricity transmission infrastructure projects in the country, irrespective of their risk profile or impact.

(58) The most common risk evaluation approach applied in the EU Member States is the Capital Asset Pricing Model ('CAPM'). The CAPM model focuses on the identification of the level of systematic risk for the overall transmission activity through the "beta" coefficient, which is usually included in the formula for the weighted average cost of capital ('WACC').

(59) Table 5 below describes the parameters and their values used for the calculation of the WACC. ACER notes that all, but two Member States (BG, SI) apply CAPM to determine the allowed cost of capital for regulated infrastructure. In Slovenia the cost of equity is determined on the "risk premium model" (cost of equity = cost of debt + 3%), while in Bulgaria the determination of the cost of capital is based on NRA's expert assessment. The comparison of the provided WACC values in Table 5 is not always straightforward due to their different format (i.e. nominal or real, pre-tax or not), but they are mostly in the range of about 3-6%.

[52] GR: official deadline by the NRA (RAE) is end of 2023.

(60) ACER notes that the parameters for setting the WACC vary across the EU Member States (and their variation increased compared to the one observed by ACER in 2014):

a) Risk free rate varies between -1.21% (IE) – 5.21% (RO), with 8 Member States below 1%, 7 Member States between 1-2%, 5 Member States between 2-3%, 1 Member State above 3% (i.e. Romania with the highest value), while Luxembourg did not publish this value;

b) The Levered beta (i.e. market related risk) varies between 0.38 (HR) – 1.05 (SK), on average the value is 0.72 (with about half of the Member States above and about half of the Member States below this value)

c) Market risk premium varies between 3.5% (BE) – 7.55% (IE), on average the value is 5.2% (14 Member States between 3.5%-5.5% and 6 Member States between 5.51%-7.55%)

(61) ACER considers that finding an appropriate risk/reward ratio to determine the allowed or target revenue of the relevant TSOs is of utmost importance in avoiding under- (or over-) investment in electricity transmission infrastructure. ACER notes that benchmarking with other EU Member States are important tools in defining or approving the relevant parameters.

Table 5: Evaluation of systematic risk for the transmission activity

Country	Capital Asset Pricing Model (CAPM)	Weighted Average Cost of Capital (WACC)[53]	Risk free rate	Levered beta (i.e. market related risk)	Market risk premium	Notional capital structure (notional gearing)
AT	Yes	3.72%	1.87%	0.85	5.00%	Yes
BE	Yes	4.68%[54]	2.40%	0.53	3.50%	Yes
BG	No (NRA makes an expert assessment)					
HR	Yes	4.03%	2.70%	0.38	3.75%	Yes
CZ	Yes	6.54%	2.04%	0.90		No
DK	Yes	3%	1.16%	0.90	6.00%	Yes
EE	Yes	4.51%	1.41%	0.69	5.00%	Yes
FI	Yes	5.24%[55]	1.76%	0.72	5.00%	Yes
FR	Yes	4.6%	1.70%	0.78	5.20%	Yes
DE	Yes	No WACC applied[56]	0.74%	0.81	3.7%	Yes
GR	Yes	6.1%	0.5%	0.80	5.50%	Yes
HU	Yes	3.36% (real, pre-tax)	0.46%	0.66	4.4%	
IE	Yes	3.8%	-1.21% to -0.8%	0.78-0.89	6.9%-7.55%	Yes

[53] The value means the nominal pre-tax value for the current regulatory period unless otherwise specified.
[54] BE: Equity part
[55] FI: 5.24% for WACC 2023, number updated annually as the risk-free rate is determined annually.
[56] DE: the equity return consists of a risk free rate, an equity risk premium and taxes. In brief, the equity risk premium consists of a market risk premium multiplied with a beta plus a correction (0.395). The market risk premium reflects the premium on investments in a fully diversified portfolio. The beta is the proxy for company specific risks.

Country	Capital Asset Pricing Model (CAPM)	Weighted Average Cost of Capital (WACC)[53]	Risk free rate	Levered beta (i.e. market related risk)	Market risk premium	Notional capital structure (notional gearing)
IT	Yes	5.0% (real, pre-tax)	0.13%	0.651	5.87%	Yes
LV	Yes	2.72% (real, pre-tax)	0.39% (plus 0.52% country risk premium)	0.74	5.25%	Yes
LT	Yes	4.09%	1.27%	0.75	5.00%	Yes
LU	Yes	4.81%	Not publicly available	Not publicly available	Not publicly available	Yes
NL	Yes	2.76% (average for 2022-2026 period)[57]	-0.01%	0.63	5.00%	Yes
PL	Yes	5.781%	2.727%	0.724	5.00%	Yes
PT	Yes	4.7462% (nominal pre-tax)	0.06%	0.62	5.37%-6.51%	Yes
RO	Yes	6.39% (real)	5.21%	0.70	6.50%	Yes
SK	Yes	4.99%	1.30%	1.05	5.08%	No
SI	No (cost of equity is determined on the “risk premium model” (cost of equity = cost of debt + 3%)					
ES	Yes	5.58%	2.97%	0.72	4.75%	No
SE[58]	Yes	3.92%[59]	0.90%	0.51[60]	6.68%	Yes
Total	23 Yes, 2 No		-1.21% - 5.21%	0.38 – 1.05	3.5% - 7.55%	21 Yes, 3 No

3.4. National framework for the evaluation of investments

(62) ACER deems that Article 17 of the TEN-E Regulation aims at avoiding that high value investments for the society are not put forward by the TSOs or other project promoters (i.e. they become “missing investments”) due to high risk for the investor.

(63) Further, ACER notes that a socially needed investment could be “missing” also for other reasons (such as TSO’s financial interests preferring other investments, bias regarding the cost

[57] NL: The WACC has a different value each year in the regulatory period. Another WACC is set for offshore projects.
[58] SE: Values to be recalculated by NRA after court proceedings now have ended.
[59] SE: 3.92% nominal was the original decision of the NRA. In court proceedings, the NRA conceded 4.12% (nominal).
[60] SE: A levered beta of 0.51 was the original decision of the NRA. In court proceedings, the NRA conceded 0.52.

remuneration or distortions in providing efficient and effective incentives) as well as other barriers under limited control of TSOs and NRAs (e.g. permitting).

(64) ACER deems it of utmost importance that such "missing investments" (including more efficient alternative solutions to an investment need) are identified by TSOs and NRAs, especially regarding projects which would potentially be of top interest for the implementation of European policies.

(65) As a precondition for the identification of "missing investments", the NRA shall scrutinise the investment needs (gaps) of the network. This assessment should be based on a sufficient level of technical analysis (carried out by the TSO or other entities) and on data that pertains to an appropriate time horizon.

(66) Afterwards, the NRA shall examine whether the projects in the national network development plan ('NDP') put forward by the TSO or other project promoters match the identified investment needs and if not, it may require the transmission system operator to amend its NDP[61].

(67) When approving projects, the NRA should evaluate the costs and benefits of the projects and assess the uncertainties and the consequent risks for the society. If the risks accompanying an investment are too high for the society (e.g. due to high uncertainty of the benefits) the costs may not be borne by the society (i.e. the NRA may not approve the project within the regulated regime and recover the relevant costs via the network tariffs).

(68) The ACER evaluation of the NDPs identified that in the vast majority (more than 2/3) of the Member States the NRAs perform an examination on whether the NDP covers all investment needs identified during the corresponding consultation. In the remaining Member States, the NRA has no such right or did not actually perform this activity. ACER observers that in some instances the examination revealed that the NDP did not cover all investment needs identified during the consultation process, and consequently amendment of the NDP was requested[62].

(69) In more than two-third of the Member States (17 out of 25) the NRA carries out an assessment of individual projects for the purpose of inclusion/adoption of the project in the NDP, while in less than third (8 out of 25) of the Member States there is no assessment at the level of individual projects (BG, CZ, FI, NL, SK) or such evaluation (i.e. for the inclusion/adoption of the project) is carried out by the relevant ministry and not the NRA (BE, DK, ES). In these latter instances, the NRA may still evaluate budgets (ex-ante decision) based on CBA and incurred costs (ex-post decision) based on unit/reference costs as benchmarking techniques (e.g. BE).

(70) Where a project specific assessment is carried out by the NRA, in most instances (12 out of 17), the assessment, at least for some projects of the NDP, is based on a cost-benefit analysis ('CBA'). This means that the TSO, the NRA, or their consultants provide a CBA where at least some of the benefit indicators are monetized (i.e. expressed in EUR or other currency). In the remaining five instances (AT, DE, HU, IE, PL), the individual project assessment is only

[61] Cf. Article 51(5) of Directive 2019/944.
[62] Cf. ACER Opinion No 05/2021 on the Electricity National Development Plans, p.12.

quantitative and/or qualitative. In some cases, the decision to include a project in the NDP is based on expert judgement.

(71) The CBA is often (5 out of 12) carried out depending on the expected CAPEX level: i.e. detailed CBA is required only for projects above certain CAPEX threshold in five Member States (BE- above € 20 million, GR-above € 50 million, HR- € 5.3 million, IT – above € 25 million for new projects and above € 50 million for other network investments, LU- € 5 million).

(72) In addition, in Greece, the requirement of a CBA is also limited to interconnections with neighbouring countries and for interconnections of autonomous island grids to the Greek mainland system, while in Slovenia the CBA is limited to investments with cross-border impacts.

(73) The national practices using CBA for project evaluation with some monetised benefit indicators is presented in Table 6 below. The most frequently monetised benefits are the social economic welfare (reflecting market integration and integration of renewable energy sources), variation of losses, security of supply and sustainability/climate benefits. No major recent updates have been reported by any country regarding such project evaluation, except Italy, who reported introduction of two new benefit categories in its CBA methodology.

Table 6: Description of the Cost Benefit Analysis applied in the Member States for the purpose of inclusion/adoption of individual projects in the national network development plan.

Country	Monetised indicators	Projects subject to CBA and other info
BE	-Environmental impact ("cost", monetised) -Electricity losses ("cost", monetised) -Security of Supply (quantified only) -Transportation capacity (quantified only) -Losses reduction (quantified only) -Quality of supply (quantified only) -RES integration (quantified only)	Detailed CBA is required only for high CAPEX projects (above 20 million EUR)[63]. The preferred solution is compared to at least one alternative, which the TSO has to provide.
HR	- Decrease of losses in the grid decrease of costs for expected electricity not supplied - Decrease of CO_2 emissions - Increase of transmission capacity - Decrease of costs for redispatching	Project with a value of more than 5.3 million €
EE	*Not provided*	For major projects the TSO also submits to the NRA a CBA made by an independent expert. The NRA may involve other experts for the evaluation. The evaluation of the justification of the investments is based on TSO's justifications and explanations about the necessity of the investments and possible risk scenarios if the investments were not made.
FR	- Variation of redispatching costs - Variation of network losses - Variation of expected energy not supplied - Avoided CO_2 emissions	The TSO has to elaborate a specific CBA of the different possible strategies (including the "no-investment" strategy) for all investment projects for which the estimated budget exceeds or is equal to €5 million.

[63] BE: For the period 2020-2023, the TSO introduced 23 CBAs for 23 projects, including PCIs (Alegro, Brabo II&III, Lonny-Gramme).

Country	Monetised indicators	Projects subject to CBA and other info
		The NRA is particularly committed to assessing the sizing of the project and its adequacy with the needs of the market, in particular with regard to the development of competition, the improvement of security of supply and reduction of congestion[64].
GR	The CBA methodology currently applied (RAE decision 590/2021) is ENTSO-E's CBA 3.0.	For high CAPEX projects (above € 50 million), for interconnections with neighboring countries and for interconnections of autonomous island grids to the Greek mainland system a CBA is required within the NDP approval process. For projects without CBA requirement, a TSO justification is provided, in order to be assessed by the NRA. The justification should be based on criteria such as improvement of security of supply, overcoming technical issues, access to new users, increasing rating / capability of network components, losses reduction, etc.
IT	B1. Variation (increase) of the socio-economic welfare (SEW) related to the day-ahead market functioning and to increased transfer capacities between Italian network zones or at the borders; B1b: reduction of variable generation costs after interconnecting small isolated systems B2a. variation ([counted positive if:] reduction) of network losses calculated by using probabilistic [network] simulations; B2b. variation (counted positive if reduction or counted negative if increase) of network losses calculated through by using simplified approaches via load flow simulations at peak load and conventional coefficients of utilisation of losses at peak load; d) B3a. variation (counted positive if: reduction or counted negative if: increase) of expected energy not supplied (EENS) by using probabilistic simulations; B3b. variation ([counted positive if:] reduction) of expected energy not supplied by using load flow simulations or by simplified calculations for "radial" portions of the transmission network; B4. Avoided or deferred costs (or [counted negative] additional costs) related to generation capacities subject to remuneration schemes which supplement or replace the revenues of the day-energy market and of the dispatching services market, in the absence of double counting with benefits B1 B7 or B8; B5a. greater integration of production from renewable energy sources (RES) calculated	The minimum requirements for the CBA are defined by the NRA (ARERA) decision 627/2016 and its updates. The last update on 24 January 2023, by ARERA decision 15/2023. Based on the latter decision, the CBA is carried out for each project involving new investments (e.g. a new substation, a new line) with expected CAPEX above € 25 million and for all other projects (e.g. network reinforcements, network reconfiguration, partial undergrounding, dismissal of existing part of lines) with expected CAPEX above € 50 million.

[64] FR: https://www.cre.fr/Documents/Deliberations/Communication/projets-d-interet-commun

Country	Monetised indicators	Projects subject to CBA and other info
	by probabilistic network simulations (local congestion); B5b. greater integration of production from renewable energy sources (RES) calculated using static load flow simulations (local congestion); B5s. greater integration of production from renewable energy sources (RES) due to the results of dispatching services market, in the absence of double counting with benefits B1 B7 or B8; B6. Avoided investments in electricity transmission infrastructure which would have otherwise been necessary in response to mandatory requirements (e.g. respect of law); B7. Variation ([counted positive if:] reduction or [counted negative if:] increase) in costs for network services and procurement of resources on the dispatching services market – calculation based on nodal simulations; B8. Variation ([counted positive if:] reduction or [counted negative if:] increase) in costs for network services and procurement of resources on the dispatching services market – calculation based on zonal simulations.	
LV	*Not provided*	For major projects the TSO also submits to the NRA a CBA made by an independent expert. The NRA may involve other experts for the evaluation. The evaluation of the justification of the investments is based on TSO's justifications and explanations about the necessity of the investments and possible risk scenarios if the investments were not made.
LT	- Increased security of supply; - Reduction of environmental pollution; - Creation of a transmission and (or) distribution system of peak consumption capacity for commercial or final purposes; - Avoided reduction in demand for natural gas or electricity; - Benefit from the integration the Baltic Sea region into the EU common natural gas or electricity market, - Increasing domestic competition; - Regulating companies may specify other benefits with proper justification.	Projects are approved based on benefit/cost ratio and judgment of NRA technical experts. Rules on the procedure for evaluation and appraisal of investments of natural gas, electricity, liquefied petroleum gas companies[65] provides the specific rules, how each benefit should be monetised.
LU	*Not provided*	For new cross-border projects and projects with an estimated value above € 5 million (€ 2 million in case of IT projects) the TSO submits a CBA along with other documents.
PT	- Social economic welfare (reflecting market integration) - Security of supply	The NDP includes a CBA. There is no published CBA methodology yet, but when drafting the NDP, some indicators are

[65] Link to the Rules on the procedure for evaluation and appraisal of investments of natural gas, electricity, liquefied petroleum gas companies; https://www.e-tar.lt/portal/lt/legalAct/TAR.930473CEC480/asr

Country	Monetised indicators	Projects subject to CBA and other info
	- Sustainability (RES integration variation in losses variation in CO2 emissions)	displayed as monetised (B1, B2, B3). The TSO adopts the ENTSO-E CBA methodology.
RO	*Not provided*	The estimated benefits that justify the efficiency of every investment in the electricity network are evaluated ex ante and also ex post by the network operator and reported to the NRA (ANRE). ANRE removes the investments that prove ex post to be inefficient from the RAB, because the expected benefits are not realised.
SI	*Not provided*	TSO carries out CBA for investments with cross-border impacts and investments in projects of common interest

Note: The Table includes only the Member States which apply a cost benefit analysis at least for the major projects of the national network development plan, with some monetized indicators

(74) While, based on the information collected by ACER, there is no clear evidence that such a problem occurs, given that the needs identification is an important step for setting the right goals for the system planning, and from the collected information it seems that in many instances this step is not in place or not adequately developed in the national transmission system planning framework, ACER sees a great room for improvement in how investment needs are identified.

(75) Similarly, CBA methodology (at least with some monetised indicators) are only partly used for the evaluation of the investment, while in ACER's view they could make significant support in prioritisation between proposed projects and alternatives that address the same need.

3.5. General risk mitigation and incentives by the national regulatory frameworks

Cost recovery by the national regulatory frameworks:

(76) Costs incurred by system operators are typically recovered via network tariffs, for which as a first step, the allowed or target revenues of the network operators (including the remuneration method for system operators' costs) are determined.

(77) In what regards cost recovery, the regulatory frameworks can be split into two main categories: Cost-of-service regulation (cost-plus or rate-of-return) and incentive regulation (revenue cap or price cap)[66].

(78) As shown in Table 7 below, incentive regulation is currently the most frequent approach for cost recovery of electricity transmission projects: for investment cost (CAPEX) it is applied in about

[66] For cost-of-service regulation the revenue is typically set equal to historical costs and revised over time (in case of cost-plus regulation the revenue is adjusted frequently (e.g. annually) to equal actual costs, while in rate-of-return regulation the revenue is reset at irregular intervals, but typically before each regulatory period to maintain a reasonable allowed return. For incentive based regulation, the revenue is set equal to forecast costs and reset at irregular intervals, but typically before each regulatory period to still fit for purpose.

55% of the Member States), while for operational and maintenance costs (OPEX) it is applied in about 70% of the Member States.

(79) In the vast majority of the Member States (i.e. about 75%) both CAPEX and OPEX are subject to similar regime: i.e. either they both fall under cost-of-service regulation or they both fall under incentive regulation. In about 25% of the Member States (BE, CZ, FR, GR, IE, IT) different frameworks for CAPEX and OPEX apply, with all, but one using cost-of-service regulation for CAPEX and incentive regulation for OPEX.

(80) Furthermore, ACER finds that except one Member State (PT), in all other Member States the CAPEX and OPEX costs are treated as separate budgets (i.e. no TOTEX approach, which considers CAPEX and OPEX together), which could potentially lead to some bias in some Member States regarding the chosen technical solutions.

(81) In Portugal, since 2022, a revenue cap regulation is applied to TOTEX, and an efficiency target is set to both CAPEX and OPEX components. This practice is described in more detail amongthe relevant national practices below.

(82) Italy is introducing a TOTEX approach from 2024. A first phase of the TOTEX regulation has been introduced by the NRA's (ARERA) regulatory decision 163/2023 of 18 April 2023. From 2024, new expenditures will be shared according to CAPEX and OPEX rates to be set by the NRA considering both CAPEX/OPEX historical shares and forward-looking estimates, instead of using actual CAPEX and actual OPEX. A more advanced implementation of the TOTEX regulation is expected (for the electricity transmission sector) from 2026, based on an expenditure plan submission by the TSO for NRA approval. The CAPEX/OPEX rates would be set with a stronger role of the forward-looking estimates from the TSO investment plan. The rules for this second implementation phase are currently under consultation.

(83) Sweden also mentioned some considerations of a potential transition towards a TOTEX regulation in the future.

(84) As underlined by ACER in its Position Paper (November 2021), the applied regulatory regimes have a significant impact on the TSOs investment strategies: for example with a "rate of return" regulation, where the remuneration principle is based on repaying regulated entities for the incurred costs plus a rate of return reflecting the cost of capital, solutions with a higher cost generate bigger profits for the investors. Therefore, when addressing a need to invest, lower cost solutions may be less financially attractive for the TSO compared to the higher profits of higher cost solutions.

(85) On the other hand, setting revenue or price caps on the remuneration to the TSOs can also have some negative impact to the level of investment, especially at systems where there is a need for scaling up investments, while the TSO is incentivised to cut its costs.

(86) Last, in those regulatory regimes, where CAPEX is remunerated with rate-of-return while OPEX is under incentive regulation, TSOs' investment decisions may be distorted due to an additional CAPEX-bias, resulting in lower attractiveness of alternative solutions, which are more OPEX intensive.

(87) The options to potentially mitigate such CAPEX-bias, where present, include application of total-expenditure (TOTEX) regulation. However, as also pointed out by NRAs the implementation of such approaches face several complexities, as they may require larger changes in the regulatory framework to accommodate them.[67]

(88) ACER notes that compared to its findings in 2014[68], the applied regulatory frameworks for the treatment of CAPEX and/or OPEX have changed in more than 25% of the Member States, without observing a clear trend. While in four cases the NRAs moved from cost-based regulation towards incentive regulation (for both CAPEX and OPEX: DK, LV, for CAPEX: CZ, for OPEX: GR), there are also three Member States where the NRA replaced the formerly applied incentive regulation by cost-of-service regulation (for both CAPEX and OPEX: EE, for CAPEX: IE, for OPEX: PL). One country (PT) moved from the approach of treating CAPEX and OPEX separately towards a TOTEX approach.

Table 7. National regulatory frameworks

Country	Regulatory period	Regulatory framework for CAPEX	Regulatory framework for OPEX
AT	1 year	Cost-plus	Cost-plus
BE	4 years	Rate-of-return	Revenue cap
BG	1 year	Rate-of-return	Rate-of-return
HR	1 year	Cost-plus	Cost-plus
CZ[69]	5 years	Revenue cap	Rate-of-return[70]
DK[71]	2 years	Revenue cap	Revenue cap
EE[72]	Length is not defined[73]	Rate-of-return	Rate-of-return
FI	8 years[74]	Revenue cap	Revenue cap
FR	4 years	Cost-plus regulation for investments in “network” projects Revenue Cap regulation for investments in “non-network” projects (information systems and real estate).	Revenue cap
DE	5 years	Revenue cap	Revenue cap
GR[75]	4 years	Cost-plus	Revenue cap
HU[76]	4 years	Price cap	Price cap
IE[77]	5 years	Rate-of-return	Revenue cap

[67] CEER Status Review Report on Regulatory Frameworks for Innovation in Electricity Transmission Infrastructure (p.15) https://www.ceer.eu/documents/104400/-/-/8c2aace7-5601-8723-4d45-337073af38d5
[68] ACER Recommendation No 03/2014, p.15
[69] CZ: In 2014, CAPEX: cost-plus, OPEX: Revenue cap, Regulatory period: 2010-2015 (6 years)
[70] CZ: with incentive-based regulation elements built in
[71] DK: in 2014, CAPEX and OPEX: Cost-plus
[72] EE: CAPEX and OPEX: Revenue cap, Regulatory period: 1 year
[73] EE: The length of the regulatory period depends on the frequency of approval of TSO network charges (the TSO may submit an application for the approval of network charges each year or less frequently).
[74] FI: two 4-year sub-periods
[75] GR: in 2014, CAPEX and OPEX: Rate-of-return
[76] HU: in 2014, CAPEX and OPEX: Revenue cap
[77] IE: in 2014, CAPEX and OPEX: Revenue cap

Country	Regulatory period	Regulatory framework for CAPEX	Regulatory framework for OPEX
IT	4+4 years[78]	Rate-of-return	Price cap
LV[79]	2-5 years[80]	Revenue cap	Revenue cap
LT[81]	5 years	Price cap	Price cap
LU	4 years	Revenue cap	Revenue cap[82]
NL	5 years	Revenue cap	Revenue cap
PL[83]	1 year	Rate-of-return	Cost-plus
PT[84]	4 years	Revenue cap (for TOTEX)	Revenue cap (for TOTEX)
RO	5 years	Revenue cap	Revenue cap
SK[85]	5 years	Revenue cap	Price cap[86]
SI[87]	1 year	Revenue cap	Revenue cap
ES	6 years	Rate-of-return[88]	Rate-of-return
SE	4 years	Revenue cap	Revenue cap
Total	6 (1-2 years) 14 (4-5 years) 3 (6-8 years, but with mid-term review) 2 (Not defined, other)	14 incentive regulation 11 cost-of-service	18 incentive regulation 7 cost-of-service

General risk mitigation by the national regulatory frameworks:

(89) Investment in energy infrastructure entails certain risks, which the regulatory frameworks can fully cover or partially mitigate for the project promoters, while providing them a fair and sufficient risk/revenue balance for investing.

(90) ACER considers that all project risks, in general, can be grouped under the following categories of risks from the perspective of project promoters:

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[78] IT: 4+4 years: 2016-2023 with two 4-year sub-periods (2016-2019 and 2020-2023)
[79] LV: in 2014, CAPEX and OPEX: Rate-of-return
[80] LV: The duration of the regulatory period can be from two to five years and the TSO submits a justification for the regulatory period used in the tariff calculation.
[81] LT: in 2014, CAPEX and OPEX: Revenue cap
[82] LU: only for controllable OPEX
[83] PL: in 2014, CAPEX: cost-plus, OPEX: Revenue cap. The NRA indicated that the change of the regulatory framework for OPEX from benchmarking to cost plus took place in an unstable geopolitical situation with regards to higher uncertainties/lower predictability for grid planning.
[84] PT: in 2014, CAPEX: cost-plus, OPEX: Revenue cap; Regulatory period: 3 years.
[85] SK: in 2014, CAPEX and OPEX: Price cap
[86] SK: OPEX are divided into two categories in the regulatory framework: 1. Personal OPEX - real personal expenditure connected with regulated activity in 2021 evaluated each year by average index of nominal salary in economy. 2. OPEX - operational costs - the average historical data (last 3 years) are subject to the core inflation adjustment and to the efficiency factor adjustment. Additionally incurred increased operating costs that were not caused by the activities of the regulated entity, but were caused by the additional changes in the national and EU legislation, by the unusual market situation or by the natural disasters that are not covered by insurance, and research and development costs are reflected in the market factor coefficient in the transmission as well as distribution regulation as eligible operating costs. Additionally incurred OPEX must be approved by the regulatory authority.
[87] SI: in 2014, Regulatory period: 3 years
[88] ES: Rate-of-return for investment after 1998 and Revenue-cap for investments before 1998

a) Risks of cost overruns: The risk that during development, construction, operation or maintenance of a project, the actual costs turn out to be higher than the expected project costs (applicable when costs are approved ex-ante by NRAs).

b) Risks of time overruns: The risk that development and construction of a project takes longer than anticipated by the project promoters. This risk can translate into non-timely compensated costs for project promoters, depending on how investments during construction are treated.

c) Risk of underutilised or stranded assets: Stranded asset risk is the risk that an asset will underperform both in terms of availability or in terms of actual lifetime vs. regulatory lifetime, causing a potential reduction of revenues for the project promoter. Volume risk: The risk that the demand for the services of the project will unexpectedly decline (or will not rise to projected levels), due to reasons which are not under the control of the project promoters, potentially causing reduction of revenues for the project promoter.

d) Risk of some costs being considered inefficient: The risk that costs are not considered as being efficiently incurred based on benchmarking or other measures (applicable when such measures are used by NRAs).

e) Risks of company liquidity: The risk that the project promoter will be temporarily faced with insufficient cash and/or cash equivalents to meet its financial commitments, for example because allowed revenues and expenditures are significantly not aligned in time. Liquidity risks may especially be a problem where projects have high expenditures compared to the allowed overall revenues of a project promoter.

(91) Based on NRAs' responses (as shown in Table 8 below) the project promoters' risks are generally covered/ mitigated in most Member States by the default national regulatory framework. The means of risk coverage or mitigation vary across the Member States. In the remaining instances, certain risks were deemed marginal in the national context or are intentionally left to be borne by the project promoters (and are not mitigated by the regulatory framework) to incentivise timely and efficient investments.

(92) ACER's findings regarding the risk mitigation by the default regulatory framework for different risk categories are the following:

a) Risk of cost-overruns is at least partially mitigated in all, but one the Member States. where the information was provided. ACER notes that the risk of cost-overrun does not apply (i.e. fully mitigated) to TSOs in cost-of-service regulation systems as long as the actual costs are incurred efficiently and allowed by the NRA for the purpose of cost recovery. When some ex-ante limits are set by the NRA, TSOs may face the risk of cost overrun, which may be partially mitigated via various regulatory means, such as the ex-post approval of part of the CAPEX overrun, etc.

b) Risk of time overruns is fully mitigated in almost half of the Member States (i.e. 10 out of 24). The risk of time-overruns does not apply to TSOs in regulatory systems where higher costs due to longer development or construction times are approved by the regulator or expenditures incurred before the commissioning of the project are included in the

Regulatory Asset Base ('RAB') or recovered by other means. ACER notes that in eight Member States (CZ, FR, GR, IE, IT, LU, SK, SE) the risk of time-overruns is partially mitigated, e.g. under certain conditions and/or at a lower rate than WACC. Risk of time overrun is fully left with the project promoter in six Member States (FI, DE, HU, NL, SI, ES), i.e. the regulated investment is remunerated after it enters into operation.

c) Risk of underutilised or stranded assets are fully/partly covered to the TSOs in most of the Member States (i.e. 17 out of 24), for example by keeping these assets in the RAB and having the costs for the assets reimbursed without considering the underutilisation. Risk of underutilised or stranded assets is reported to be non-mitigated in seven Member States (EE, FI, DE, IE, LV, SK, ES). In some of these instances the risk is limited to stranded assets only.

d) Only regarding the risk that costs are not considered as being efficiently incurred based on benchmarking or other measures used by NRAs, there is a relatively high level of exposure of TSOs, i.e. most of the Member States (i.e. 16 out of 24) reported that such risk for the TSO is not mitigated. In the remaining Member States such risk is at least partially mitigated. In the vast majority of the Member States the NRA evaluate if the costs are reasonable and efficiently incurred with a view to including the investment costs in the RAB. The most frequently used tools to make such an evaluation are the unit/reference costs and (corporate) benchmarking techniques. The assessment of the efficiency of the incurred (actual) costs of each project is carried out on a case-by-case basis and inefficient costs are generally not reimbursed. ACER notes that the pass-through of costs to network users is a common regulatory measure for mitigating risk for promoters. The pass-through of (efficiently incurred) costs is a risk mitigation measure inherent in systems based on cost-of-service regulation. NRAs adopting incentive regulation schemes often apply the pass-through principle for certain cost categories (i.e. costs deemed non controllable are not accounted within the existing caps). The most frequently reported cost pass-through categories include the costs of system services (e.g. BE, DK, FI[89], FR[90], HU[91], IE[92], LU[93], NL[94], SI[95]), the cost of grid losses (e.g. BE, CZ, DK, FI, LU, RO[96]), Inter-TSO compensation (ITC) related costs due to transit losses (e.g. BE, EE, HU, IE, IT, RO, SI), TSOs participation to ENTSO-E and other European platforms (e.g. BE, DK, FI, IE[97], IT, RO), organised markets and/or generator database related costs (e.g. FI, IT[98]) and fees/taxes (e.g. GR[99],

[89] FI: Costs from maintenance of reserve capacity, balancing
[90] FR: Balancing reserves contracted, congestion cost
[91] HU: Costs of ancillary services
[92] IE: Costs of ancillary services and balancing
[93] LU: Auxiliary services
[94] NL: Congestion management costs
[95] SI: Costs in point I-IV. of Article 3. of the Use of Congestion Income methodology, costs related to energy for system balancing and imbalances costs due to system balancing.
[96] RO: A new tariff component to cover the cost of electricity for network losses due to increased market electricity price.
[97] IE: CORESO subscription
[98] IT: Cost of database for the generation plans
[99] GR: Local authority fees and duties, indirect taxes, rights of way,

LT, LU, RO), but some other cost categories were also reported (e.g. FR[100], DE[101], GR[102], IE[103], LU[104], NL[105], RO[106], SI[107], SE[108]).

e) Risk of company liquidity are fully or partially mitigated in most Member States (21 out of 24), by various means, including reasonable costs of financial assets being taken into account when calculating the realised adjusted profit (e.g. FI), CAPEX top-up that ensures investment costs being counted directly to the allowed revenues (e.g. DE), through working capital considered in RAB (e.g. GR), etc. Risk of company liquidity is not mitigated in three Member States (DK, FR, LV).

Table 8. Risk coverage by the default national regulatory frameworks

Country	**The default regulatory framework covers/mitigates (for the TSO):**				
	Risk of cost overruns (efficiently incurred costs)	**Risk of time overruns**	**Risk of underutilised or stranded assets**	**Risk of some costs being considered inefficient**	**Risk of company liquidity**
AT	Yes	Yes	Yes	No	Yes
BE	Yes	Yes	Yes	No	Yes
BG	Not clarified	Not clarified	Not clarified	Not clarified	Not clarified
HR	Yes	Yes	Yes	Yes	Yes
CZ	Yes	Partially[109]	Yes	No	Partially[110]
DK	Yes	Yes	Yes	No	No[111]

[100] FR: Real estate investments
[101] DE: Permanently non-controllable costs as per §11(2) Incentive Regulation Ordinance: https://www.gesetze-im-internet.de/aregv/
[102]GR: rights of way, compensations offered on retirement
[103] IE: Distribution Use of System ('DUoS') Costs
[104] LU: Personnel formations costs; Complementary pension costs resulting from obligations signed prior to 2010; Use of infrastructure of other network operators; Pre-study costs; Costs for transnational cooperation; R&D costs
[105] NL: Costs of energy expenses, after application of a bonus/malus scheme; costs of energy transportation by nearby transport networks
[106] RO: Any exceptional costs, such as expenses related to COVID pandemic or maintenance costs caused by extraordinary meteorological conditions
[107] SI: Compensation for the operation of the NRA, compensation for labour costs, which are refunded and are not state aid
[108] SE: Payment due to interruption in delivery according to the Swedish Electricity Act, however not for interruptions above 24 hours.
[109] CZ: Return on not-yet-completed investments (only for the investments which are being activated gradually and longer than 2 years, with value exceeding cca. € 20 million in a year.)
[110] CZ: Current regulatory methodology allows minor changes in covering annual adjustments of values (planned vs. actual) into tariffs. That slightly reduce the risk of company liquidity.
[111] DK: Liquidity is TSOs own responsibility and should be covered in the project total estimate

Country	The default regulatory framework covers/mitigates (for the TSO):				
	Risk of cost overruns (efficiently incurred costs)	**Risk of time overruns**	**Risk of underutilised or stranded assets**	**Risk of some costs being considered inefficient**	**Risk of company liquidity**
EE	No mitigation ex ante, but the extra cost could be covered ex post, based on TSO application and NRA approval	Yes	No[112]	No[113]	Yes
FI	No[114]	No	No[115]	No	Yes
FR	Partially[116]	Partially[117]	Partially[118]	No[119]	No[120]
DE	Partially[121]	No[122]	No	Partially[123]	Yes
GR	Yes	Partially[124]	Yes	No	Yes

[112] EE: According to the national law, when calculating the justified return and the depreciation of fixed assets to be included in the price, only the fixed assets required for provision of the network service are taken into account. Fixed assets that the undertaking does not use for the provision of the network service are excluded.
[113] EE: The national law states that any costs to be included in the tariff must be justified and reflect a cost-effectiveness-based approach. However, there is no cost, which is intentionally left to be borne by the TSO, if the cost is related to the provision of the network service and it is justified and reflect a cost-effectiveness based approach.
[114] FI: the NRA uses pre-defined cost catalogue prices to determine RAB which are based on historical costs, the CAPEX overruns are considered eventually when the cost catalogue is updated. Therefore, during the regulatory period TSO will bear the costs of overruns, but the cost will level off in longer period.
[115] FI: The remuneration does depend on the utilization of the asset, i.e. any asset that is out of use is not part of RAB.
[116] FR: For projects under €30 million the risk of cost overrun is fully covered by the tariff. For projects over € 30 million, risks of cost overrun are only partially covered by the tariff.
[117] FR: Assets under construction are remunerated at a "cost of debt" lower than WACC.
[118] FR: Recurring or foreseeable stranded costs are given an incentive-based trajectory; the cost of studies not followed through relating to large projects previously and explicitly approved by the NRA are covered by the tariff through the CRCP ('expenses and income claw-back account'); coverage of other stranded costs will be examined by the NRA on a case-by-case basis, based on substantiated proposals submitted by the TSO. Regarding disposed assets, if the disposal gives rise to an accounting gain, 80% of the disposal proceeds net of the sold asset's net book value are included in the CRCP so that network users can benefit from the greater part of the gains made from the sale of these assets, while maintaining an incentive for TSO to maximise this gain. TSO therefore keeps 20% of the profit. On the other hand, a disposal giving rise to an accounting loss will be examined by the NRA, based on a detailed dossier submitted by the TSO.
[119] FR: Only efficient costs are allowed through the investment approbation process. In particular, if the estimated costs of a project vary significantly, the TSO has to send an updated CBA of the project so the NRA makes sure the project is still efficient.
[120] FR: Such a situation has never been reported by the TSO so far. Company liquidity might become an issue in the next decade in order to finance the increase in investments due to the energy transition; a specific framework could then be studied if needed.
[121] DE: For CAPEX, assessment of budgeted vs. actual incurred costs applies. For OPEX strictly the budget approach applies.
[122] DE: The equity return is granted on the regulatory asset base which only consists of the realized investments.
[123] DE: The idea of the German incentive regulation framework is to remove inefficient costs over the course of the regulatory period in increasing shares (20% steps per year).
[124] GR: Such risk is mitigated through Working Capital considered in the RAB. However, the NRA may investigate cases of projects with time overruns and may impose penalties.

Country	The default regulatory framework covers/mitigates (for the TSO):				
	Risk of cost overruns (efficiently incurred costs)	**Risk of time overruns**	**Risk of underutilised or stranded assets**	**Risk of some costs being considered inefficient**	**Risk of company liquidity**
HU	No mitigation ex ante, but the extra cost could be covered ex post, based on TSO application and NRA approval	No	Yes	No	Yes
IE	Yes	Partially[125]	No[126]	No	Partially[127]
IT	Partially[128]	Partially[129]	Partially[130]	Yes	Yes
LV	Yes	Yes	No	Yes	No
LT	No mitigation ex ante, but the extra cost could be covered ex post, based on TSO application and NRA approval	Yes	Yes	Partially	Yes
LU	No mitigation ex ante, but the extra cost could	Partially[131]	Yes	No	Yes

[125] IE: Costs and reason for delay will be assessed individually. Costs related to time overruns may be allowed/partially allowed if efficiently incurred.
[126] IE: Assets which have been added to the RAB, but have not been energised within five years (except in the case where the programme of work was scheduled to be longer than five years or where the TAO can satisfactorily show that the delay is beyond its control) would be temporarily removed from the RAB (with all return and depreciation paused) until the point at which the asset can be energised and utilised.
[127] IE: Element of liquidity provided via return on investments.
[128] IT: In general, the CAPEX overruns are allowed, as long as the general principle of allowing revenues only when costs are efficiently incurred is safeguarded. However, as an application of the principle, a transmission project previously approved in a network development plan, was not allowed anymore to be covered by network tariffs - this NRA (ARERA) decision however was mostly linked to a further expected CAPEX increase and not an actual CAPEX overrun.
[129] IT: The remuneration of costs before commissioning aims at balancing the objectives of a sufficient level of cost recovery and a stimulus to the TSO to timely commission new projects after their construction started.
[130] IT: There is no mitigation of the risks due to shorter asset availability (early decommissioning), because an asset is expected to be operational at least for its entire regulatory lifetime (network users should not bear risk of asset permanent failure in ARERA's view, as this technology-related risk is better left on TSOs' shoulders). Non-usage risk is fully mitigated, because the remuneration of a transmission asset does not depend on its actual usage / power flow. Volume risk (referring to the electricity demand) is to a large extent mitigated. The tariff streams (which are mainly collected by DSOs and transferred to TSO) are to a large extent (90%) power-based, with a minimal (10%) energy-based component. Therefore, a potential reduction of system-wide electricity demand would have a limited impact on TSO revenues.
[131] LU: Limited time overruns are accepted in the framework and do not have any consequences. Longer time overruns have an impact on the remuneration of work in progress, by limiting the remuneration to costs of debt. In duly justified cases, the operational planning can be adjusted. The network operator has to explicitly ask for such an adjustment by submitting a written request, demonstrating time overrun is caused by events beyond their influence as network operator.

Country	The default regulatory framework covers/mitigates (for the TSO):				
	Risk of cost overruns (efficiently incurred costs)	**Risk of time overruns**	**Risk of underutilised or stranded assets**	**Risk of some costs being considered inefficient**	**Risk of company liquidity**
	be covered ex post, based on TSO application and NRA approval				
NL	Not applicable	No	Yes	No	Yes
PL	Yes	Yes	Yes	No[132]	Yes[133]
PT	Partially[134]	Yes	Yes	Partially[135]	Partially[136]
RO	Yes	Yes	Yes	Yes	Yes
SK	No mitigation ex ante, but the	Partially[137]	No[138]	No[139]	Partially[140]

[132] PL: The NRA is obliged to analyse and verify costs included in tariff calculation. Only costs considered by NRA as justified should be included in the tariff calculation.

[133] PL: There is no special regulatory measure to cover/mitigate the risk of company liquidity. The return on capital and depreciation included in the tariff calculation is expected to cover all project promoters' expenditures and handle liquidity issues.

[134] PT: In the definition of the total cost base of the revenue cap regulation, the forecasted investment costs of the projects approved in the NDP are considered in the CAPEX component. In the beginning of the next regulatory period, the RAB is recalculated with the actual investment cost incurred by the TSO that may include cost overruns, but is also subject to the efficiency targets throughout that regulatory period (does not apply for investments commissioned before 2022). Additionally, the regulation model includes a mechanism for sharing losses (also gains) that partially compensates the TSO if the return on assets deviates from the rate of return above a pre-determined value.

[135] PT: For projects that came into operation in 2022 or later, the corresponding CAPEX is included into the TOTEX components that are subject to efficiency targets. In the beginning of each regulatory period, the CAPEX component of the cost base is revaluated considering the actual investments and the more recent NDP. Additionally, in the calibration of the cost base and efficiency factors, both the economic performance (evolution of total cost per cost drivers) and the results of the European TSO benchmarking studies, conducted by CEER, are considered in qualitative terms.

[136] PT: The transition to a revenue cap regulation in 2022 decoupled the flow of allowed revenues from the costs effectively incurred by the TSO each year. Additionally, the CAPEX component incorporated in the total allowed revenues is smoothed (annual payment calculated with the yearly forecasts of CAPEX for each year of the regulatory period, discounted with the rate of return). However, the methodology adopted in the definition of the total cost base aims to ensure financial neutrality to the operator, while the rate of return (which is a cost driver of the TSO revenue cap) is partially indexed to the evolution of the yields of the Portuguese 10-year treasury bonds, thus internalizing the country's financial conditions.

[137] SK: If the project consists of several investment actions and it is possible to put some of them into the operation earlier than the whole project, this will be included into the RAB earlier and can thus, at least partially, increase the regulated entity's allowed revenues and accelerate the depreciation generation before the time when the entire project is commissioned.

[138] SK: Underutilized or stranded costs are based on the price regulation decree considered as ineligible costs of regulated entity.

[139] SK: Each regulated entity is responsible for effective utilization of assets. Once investment is inefficient, it has to be borne by the entity itself.

[140] SK: If the project consists of several investment actions and it is possible to put some of them into the operation earlier than the whole project, this will be included into the RAB earlier and can thus, at least partially, increase the regulated entity's allowed revenues and accelerate the depreciation generation before the time when the entire project is putting into the operation.

Country	The default regulatory framework covers/mitigates (for the TSO):				
	Risk of cost overruns (efficiently incurred costs)	**Risk of time overruns**	**Risk of underutilised or stranded assets**	**Risk of some costs being considered inefficient**	**Risk of company liquidity**
	extra cost could be covered ex post, based on particular system operator application and NRA approval				
SI	No mitigation ex ante, but the extra cost could be covered ex post, based on TSO application and NRA approval	No	Yes	Yes	Yes
ES	Partially[141]	No	No[142]	No	Yes
SE	Partially[143]	Partially[144]	Partially[145]	No	Yes
Total	17 Yes or ex-post or N/A 6 Partially 1 No 1 Not clarified	10 Yes 8 Partially 6 No 1 Not clarified	14 Yes 3 Partially 7 No 1 Not clarified	5 Yes 3 Partially 16 No 1 Not clarified	17 Yes 4 Partially 3 No 1 Not clarified

Note: “Yes” means that the risk is fully covered by the default regulatory framework (i.e. no such risk for the TSO), “Partially” means that the risk is only partially covered/mitigated (i.e. some risk is left with the TSO), “No” means that the risk is not mitigated by the default regulatory framework (i.e. such risk is fully left with the TSO

[141] ES: In the case of investments that have standardized costs, a deviation of up to 12.5% of the standardized cost is admitted. In the case of facilities that do not have reference values, the audited investment cost is recognized. Finally, in the case of singular projects (such as a submarine link or a STATCOM) an upward deviation of up to 25% of the investment cost authorized in the resolution of the singular character prior to its administrative processing and its commissioning.
[142] ES: Once the asset is commissioned, the TSO starts receiving a reimbursement. However, the NRA regularly carries out inspections on whether the installation is being underutilised or out of operation. If this is the case, the TSO stops receiving remuneration for the investment, operation and maintenance costs of the installation until the asset is in operation again.
[143] SE: In the current regulation for the period 2020-2023: If in the valuation method the “norm value” has been used, it also depends on how the cost overruns are relative to the norm value. Method for future decisions on revenue caps for the period 2024-2027 (incl. CAPEX) will be published at the end of October 2023.
[144] SE: If costs due to time overruns are still within the framework of effective costs, they are reimbursed fully.
[145] SE: There is an exception rule for stranded assets. For example, it may be seen as unreasonable to include an electricity network company’s asset to an industry that has just gone bankrupt if it is likely that a new industry will be established there shortly. Regarding volume risk today it depends on how big the changes are forecast to be occur in the future. Deviations from historical costs as a base have already been made on a few occasions because of this. But in the case of a potential transition to TOTEX, volume adjustment is handled directly. Method for future decisions on revenue caps for the period 2024-2027 (incl. OPEX) will be published at the end of October 2023.

Difference in the regulatory treatment of different categories of electricity transmission infrastructure projects

(93) Only a few NRAs reported any substantial difference regarding the regulatory framework based on some specific features of the electricity transmission infrastructure. These differences concern high CAPEX projects (vs. low CAPEX projects), interconnections (vs. internal projects) and offshore projects (vs. onshore projects). ACER finds no instances, where anticipatory investments are differentiated by the regulatory treatment. The description of the differences regarding project evaluation is provided in Section 4.2 above, other relevant differences are listed in Table 9 below.

(94) ACER also notes that in none of the Member State it has been reported that there is any dedicated framework for PCIs, i.e. the default regulatory framework applies to them, as well. This approach may be explained by administrative costs of registering another framework or that PCIs do not generally entail higher or lower risks than other electricity transmission projects, thus the default regulatory framework adequate to them.

Table 9. Regulatory incentives for particular infrastructure categories

Country	Difference between low CAPEX vs. high CAPEX projects
FR	Different treatment of investment projects for which the estimated budget exceeds or is equal to € 30 million: i.e. bonus/ penalty based on the difference between the project's target budget and actual investment expenses.
GR	Projects with significant economic impact ("MIP") may receive a premium rate of return, in addition to WACC. One condition for the project is a CAPEX exceeding € 500 million.

Country	Difference between interconnections vs. internal projects
FR	A specific incentive framework exists for interconnection projects, with fixed bonus for timely implementation, bonus/penalty based on the difference between the project's target budget and actual investment expenses and bonus/penalty based on the utilization of the infrastructure. Interconnection projects also have their own approval scheme (i.e. they are not approved through the approbation of RTE's annual investment program but through dedicated deliberations fixing the cross-border cost allocation).
RO	For interconnection projects there are incentives provided (surplus to WACC) due to high risks.

Country	Difference between offshore vs. onshore projects
BE	Specific depreciation periods for certain offshore infrastructures. If higher risk profile is acknowledged, additional remuneration may apply.
DE	Grid operators can apply compensation payments and grid connection costs for offshore wind farms as a surcharge on the grid fees. The regulation serves the purpose of distributing the financial burdens of the transmission system operators with connection obligations among all transmission system operators and thus also including all end consumers in the financing. The difference is that there is no regulation period for offshore investment measures, but the OPEX and CAPEX are determined annually and reflected in the levy.

Country	Difference between offshore vs. onshore projects
IE	To date the cost treatment and the incentive framework for the offshore interconnection projects have been treated on a case-by-case basis. The wider incentive framework will be developed in due course.
NL	Note: The treatment is not exclusive to offshore. It applies to all offshore project and some of the onshore projects. Cost recovery differs for offshore projects (and certain onshore national coordination projects) versus regular investments. Costs before commissioning of offshore projects are considered in the determination of the annual revenues of the TSO. For regular investments, the capitalized construction interest is part of the book value of the asset. For regular investments in asset categories with depreciation period ≤ 10 year. The WACC is also different for offshore projects.

General benefit-based incentives provided by the national regulatory frameworks:

(95) As shown in Table 10 below, based on NRAs responses in several Member States the TSOs receive benefit-based incentives (including penalties and rewards) targeting one or more specific objectives, such as cost efficiency, energy efficiency, market integration, security of supply, innovation, RES integration, etc. Additionally, as described above in the section on general risk mitigation by the national regulatory frameworks, most regulatory frameworks provide incentives (indirectly) by not reducing certain risks for the TSOs, for example timely delivery can be incentivised by only partially mitigating the risks of time-overruns for the TSOs via applying a lower rate of return (e.g. than the WACC) ahead of the commissioning, for the incurred costs. Some of the national practices providing benefit-based incentives (which are not considered as "business as usual" solutions) are described in detail below.

(96) In most instances these regulatory tools generally provide higher return or bonus for high value investments or penalty based on over-/under-performance regarding a pre-set target. In some other instances the monetary incentive is directly linked to the measurable benefits or performance targets and part of the monetised benefits (e.g. reduced energy not supplied) the investment brings to society is shared ex-post with the TSO.

(97) ACER notes that some regulatory frameworks do not provide any benefit-based incentives to target a certain objective. However, some of these objectives (e.g. cost efficiency or reduction of grid losses) may be still implicitly pursued due to the general CAPEX and OPEX treatment (e.g. via revenue or price caps).

(98) ACER considers that if the standard regulatory tools currently in place are insufficient to achieve efficient infrastructure development and/or result in some investments "being missed", systematic application of benefit-based incentives (i.e. not only upon request for individual projects), seems an appropriate tool in facilitating efficient infrastructure development and bringing additional benefits to the society.

(99) It is important that such benefit-based incentives are appropriately designed, set transparently ex-ante, ensure the investments value to the network users and reviewed periodically. They may be linked directly to measurable project benefits (e.g. energy not supplied, congestion income)

or major performance targets (e.g. increasing the level of capacity across zones available for trade, etc.).

Table 10. Benefit-based incentives (rewards or penalties) for electricity transmission development

Specific regulatory incentives for electricity transmission development[146]	Countries
to increase (cost) efficiencies	FI, FR, IT, LT, PT, RO, SK, SI, ES
to increase energy efficiency (e.g. reducing network losses)[147]	CZ, FR, LT, NL, PL, RO, SI, ES, SE
to foster market integration	AT, BE, FI, FR, IT, LT, LU, PT, SI, ES
to foster quality/reliability of supply	AT, BE, CZ, EE, FI, FR, IE, IT, LT, LU, PT, RO, SK, SI, ES, SE
to foster availability of network equipment[148]	BE, FR, DE, IE, PT, RO, SK, SI, ES
to foster security of supply	IE, LT, SK, ES
to deploy network-scale investments in non-traditional electricity transmission projects	FI, FR, IE, PT, SK, SI, ES,
explicitly targeting RES integration	AT, DE, GR, IE, LU, SK
to increase system performance[149]	IE, IT, SK, SI, ES

NATIONAL PRACTICES: Output/ performance/ benefit–based incentives

ITALY
Summary: • reward if the actual CAPEX for an increase of transfer capacities (MW) is lower than the reference CAPEX for that boundary • benefit-based reward for increases of cross-zonal transfer capacity • incentive tools for quality of supply
Incentives for electricity transmission development to increase (cost) efficiencies: The NRA (ARERA) introduced from 2020 a stand-alone incentive tool for CAPEX efficiency of network development projects increasing cross-zonal transfer capacities (up to a target capacity value). The TSO is rewarded if the actual CAPEX for an increase of transfer capacities (MW) is lower than the reference CAPEX set by the NRA for that boundary. Incentives for electricity transmission development to foster market integration: ARERA introduced from 2019 a stand-alone incentive tool for increases of cross-zonal transfer capacities (interconnections and internal zones), up to the threshold of target capacity for each boundary (decided by the

[146] Not accounting for the general regulatory treatment of CAPEX and OPEX (e.g. the fact that revenue and price caps provide incentives the TSO to reduce its costs.)
[147] Not accounting for the default feature of the revenue and price caps that it incentives the TSO to reduce its costs including the spending on network losses.
[148] The finding should be treated with caution: while in some instances (e.g. FR, PT, ES) the systematically applied incentive is clearly related to (longer term) equipment availability, in other instances the incentive is not sufficiently clarified or it seems to relate to the quality of supply.
[149] Incentives not covered above, i.e. additional to the incentives provided for energy efficiency or quality/reliability of supply, etc.

NRA, based on TSO studies). The reward is in principle equal to one annuity of benefits (80% of yearly congestion income; 20% of an annuity of expected benefit in terms of socio-economic welfare variation).

Incentives for electricity transmission development to foster quality /reliability of supply:

ARERA introduced since 2008 several incentive tools for quality of supply. The main tool is based on the network-wide performance in terms of Energy Not Supplied ('ENS') due to causes attributed to the TSO and to some partly exogenous events which the TSO accepted to include in the reference levels and in the target levels.

The targets are defined by using a yearly improvement rate, starting from the historical levels of ENS in the previous years (the 2016-2023 target values are based on ENS values recorded in 2012-2015).

Recent / ongoing / planned changes:

ARERA introduced from 2022 an incentive to reduce redispatching costs, which could also favour transmission developments (decision 597/2021) and consulted in late 2022 on possible new performance indicators, with a view to potentially introducing new measures in the new regulatory period 2024-2027.

FRANCE

Summary:

- for interconnections a bonus or penalty, based on the difference between the project's target budget and actual investment expenses
- for large projects, (i.e. over 30 million euro CAPEX) a bonus or penalty, based on the difference between the project's target budget and actual investment expenses
- for the whole envelope of investments, a penalty scheme if the total actual cost is above 120% of the overall target budget
- for non-grid investments: Cost efficiency on these investments (vs. target expenditures) is fully kept by the TSO

A specific incentive framework exists for interconnection projects, with a triple mechanism:

(1) the financial incentive for constructing interconnections within the shortest possible time is reflected in the attribution of a fixed bonus, expressed in constant euros, the amount of which is defined by the NRA (CRE) prior to the TSO's commitment decision. This fixed bonus is calculated based on the benefit for the community estimated by CRE on the basis of a cost/benefit analysis of the project. It is paid only after the project is commissioned, which is an incentive for completing the investment within the shortest possible time;

(2) the incentive for the minimisation of project implementation costs, taking the form of a bonus or penalty, based on the difference between the project's target budget and actual investment expenses;

- if the investment expenses incurred by the TSO for this project are between 90% and 110% of the target budget, no bonus or penalty will be applied;

- if the investment expenses incurred are less than 90% of the target budget, the TSO will receive a bonus equal to 20% of the difference between 90% of the target budget and the actual investment expenses;

- if the investment expenses incurred are higher than 110% of the target budget, the TSO will be applied a penalty of 20% of the difference between the actual investment expenses and 110% of the target budget;

(3) the incentive for the use of the interconnection takes the form of a bonus or penalty, calculated at the end of each year as from the commissioning of the installation, the level of which depends on actual flows compared to the flows initially forecasted by CRE. The bonus or penalty is applied during the first ten years of operation of the infrastructure.

Incentives to increase (cost) efficiencies:

For all investment projects for which the estimated budget exceeds or is equal to €30 million:

- CRE audits the budget presented by the TSO, prior to the commitment of the work-related expenses, and defines a target budget;

- regardless of the investment expenses made by the TSO (RTE), the asset enters the regulated asset base at its real value when it is commissioned (minus any subsidies);

- if the investment expenses incurred by RTE for this project are between 95% and 105% of the target budget, no bonus or penalty is applied;

- if the investment expenses incurred are less than 95% of the target budget, RTE receives a bonus corresponding to 20% of the difference between 95% of the target budget and the actual investment expenses;

- if the investment expenses incurred by the TSO are higher than 105% of the target budget, RTE is applied a penalty of 20% of the difference between the actual investment expenses and 105% of the target budget.

This mechanism is systematically applied for projects over or equal to €30 million, but it can also be applied to projects under €30 million

GREECE

Summary:

- for interconnections and other major importance projects (MIPs), a WACC adder is set
- for major importance projects penalty (reduction of premium WACC) for delays
- plans to discontinue MIP incentives and develop incentive methodology related to KPIs

Specific incentives for projects with significant impact:

Projects with significant economic (or other) impact, called "Major Importance Projects" (MIP) may receive a premium rate of return, in addition to WACC. For a project to be considered as MIP, the following two conditions must apply cumulatively:

-the project has to have CAPEX exceeding €500 million

-the project has to have a Benefit/Cost ratio exceeding 3.

MIPs are eligible for a WACC premium up to 2% for a period of 4 to 7 years. In case of delay in construction /commissioning of a MIP, the NRA (RAE) may reduce the percentage of additional return up to 1% for every year of delay.

For MIPS receiving a WACC premium, the WACC during construction period may differ (probably be less) than the approved "overall" WACC for other assets in the RAB.

The MIP incentive provision is currently foreseen to be in place until 2025.

Incentives for timely implementation of a project:

The NRA may penalise the TSO for delays in completion of projects included in the approved NDP.

Recent / ongoing / planned changes:

RAE currently plans to:

-discontinue the MIP incentive[150]

-develop the incentive methodology related to the KPIs

-establish incentives for projects which incorporate '"innovations" (e.g. non-traditional techniques such as dynamic line rating, etc.)

[150] GR: Reason: The NRA expects that by 2025 the most significant interconnections of the Greek islands to the mainland will have been approved by the NRA.

-introduce a monitoring mechanism of CAPEX expenses at aggregate/NDP level, covering the length of a regulatory period (4 years). Objective is to increase accuracy of the TSO's CAPEX estimates as provided in the NDP). -develop initial thinking about under-utilised assets.

IRELAND

Summary:
• General cost incentive
• Variety of performance incentives, such as:
  ○ Investment Planning and Delivery incentive
  ○ TAO Project Delivery incentive
  ○ Incentives for RES integration

Cost incentives allow the network company to keep some or all of the difference between the allowance and efficiently incurred expenditure. A variety of performance incentives are also included, these range from balanced scorecard incentives, which are updated annually, to target based incentives. Some examples of the performance incentives are set out below: The Investment Planning and Delivery incentive is a financial incentive on the quality and rigour of TSO end to-end processes for investment planning and delivery for the TSO. This will encompass how options and needs are identified and optimised, and how investment schemes are delivered in a timely manner. The Transmission Asset Owner (TAO) project delivery incentive gives the TAO a proportionate financial stake in the efficient and timely implementation of the TSO's investment plans. Incentive (for transmission actions) explicitly targeting RES integration: The NRA (CRU) will introduce this incentive due to its clear customer value and the fact that the TSO can play an active role in achieving RES-E targets. The TSO is required to submit a multi-year plan setting out the planned actions involved in achieving the annual RES-E targets. The RES-E incentive will reward the TSO for actions taken to achieve annual RES-E targets (2021-43%, 2022 – 46%, 2023 – 49%, 2024 – 52% and 2025 – 55%). A balanced scorecard approach is taken. The System Non-Synchronous Penetration Incentive will reward the TSO for actions taken to increase the amount of SNSP each year (2021-75%, 2022 – 78%, 2023 – 80%, 2024 – 82%, 2025 – 85%). The Renewable Dispatch Down incentive aims at the reduction of renewable dispatch down levels. Upside and downside targets have been set for the five years of PR5, with associated payments and penalties. Further description of the incentives is available under the link in the footnote[151]. Planned changes: The revenue framework for offshore has to be developed.

[151] IE: https://cruie-live-96ca64acab2247eca8a850a7e54b-5b34f62.divio-media.com/documents/CRU20154-PR5-Regulatory-Framework-Incentives-and-Reporting-1.pdf#page=52&zoom=100,92,401

PORTUGAL
Summary: • TOTEX approach • Benefit sharing • Incentive to improve technical performance
Since 2022, a revenue cap regulation is applied to TOTEX, with a building block approach, which considers OPEX and CAPEX, applying an efficiency target to both components. The CAPEX component considers the recovery of investment costs (remuneration of the net assets plus annual depreciation) of the past and those forecasted for the regulatory period, as approved in NDPs. The CAPEX is estimated for each year of the regulatory period considering past investment costs and those foreseen and approved for the regulatory period and then converted into an equivalent annual payment, using the rate of return defined by the NRA (ERSE) for the regulatory period. At the beginning of each regulatory period, the CAPEX component is reassessed in order to consider the assets that are effectively in operation and to adjust investment cost forecasts in line with the most recent NDP. The OPEX considers a theoretical (efficient) cost level. When defining this component at the beginning of each regulation period, the theoretical cost value can be reviewed after comparing it with the TSO's cost items that are considered controllable OPEX. As a complement to the revenue cap regulation applied to the electricity TSO's controllable TOTEX, a mechanism for sharing profits and losses incurred during the regulatory period has been introduced in 2022. This mechanism is activated when the return on assets goes beyond pre-defined thresholds, which aims to evaluate the deviations in profitability of the activity compared to the rate of return defined by the NRA. As the mechanism applies throughout the regulatory period[152], its activation results from a comparison of the average regulatory operating profitability verified in the years of that regulatory period with the average rate of return (WACC) for the same period. The mechanism operates progressively at three different levels of deviation in assets returns, with different sharing factors applied at each level[153]. It should be noted that the revenues resulting from incentive IMDT (described next) are not taken into account in this calculation, to avoid distorting the rationale of incentive regulation. The existence of this mechanism will allow the regularisation of the TSO's allowed revenues in the following regulatory period, namely if there are significant deviations in the implementation of investments[154]. In order to minimise the risks of tariff instability, any amounts resulting from the application of the mechanism are progressively transferred until the end of the following regulatory period, ensuring the financial neutrality of the inter-temporal transfers. Additionally, a new incentive to improve the technical performance of the operator was introduced in the same year (called IMDT). This incentive aims at providing signals to the TSO to improve technical performance of the transmission network, while assessing the capacity of the network to meet those gaps resulting from the evolution of the transmission activity in a context of energy transition and decarbonisation of the energy sector, selecting investments accordingly. The technical performance of the network is assessed based on a combined set of indicators, namely equipment availability, quality of service and cross-border capacity available to day ahead market. Overall, assuming a relative weight of 25% for each of the first two indicators and a weight of 50% for the indicator related to cross-border capacity, and depending on previously set of reference values, a premium or penalty will be added to allowed revenues of the TSO.

[152] PT: The calculation of the mechanism is carried out in the second year of the following regulatory period in order to use actual and audited values from all years of the former regulatory period

[153] PT: If profitability is close to the rate of return, no sharing takes place. If profitability deviates moderately from the rate of return, there is an equitable sharing of gains or losses between the company and consumers. In extreme cases, with excessive deviations of profitability from the rate of return, there is full replacement of gains or losses beyond this threshold.

[154] PT: Excessive deviations in investment costs may lead to a decrease in the return on assets, which will originate an additional amount of revenue to the company during the following regulatory period, if the deviation exceeds the limits pre-defined for the mechanism. In the opposite side, deviations by default in investment costs may activate the mechanism in order to the company deliver partially the excess return on assets.

SLOVAKIA
Summary: • WACC+ for innovative investments
All investment projects of the particular system operator that have been commissioned and are therefore included in the regulatory asset base (RAB) – coefficient K_{DZ}.: The value of coefficient K_{DZ} depends on the utilization rate of available sources (depreciations) by investments included in the RAB, i.e. the larger amount of investments or the higher CAPEX of the investments the higher coefficient K_{DZ}, the higher revenue cap. Incentives for specific infrastructure categories (application of WACC+): For innovative investment projects of the particular system operator – WACC+, adding value 2% to the approved WACC value – is applied, if the investment project fulfils one of the following conditions, set in Slovak NRA Decree: • investment project enabling connection of the RES generation, • investment project enabling connection of the electricity storage facilities, • investment project enabling connection facilities for charging electric vehicles, • investment project enabling connection of the ancillary services facilities into the electricity system and flexibility services, including facilities providing non-frequency ancillary services, • investment project enabling development and restoration of the facilities for system automation and digitalization, • investment project improving the quality of services for system users and electricity end-consumers. WACC+ could be applied as well for the investment projects that are co-financed by EC (up to 50%). WACC+ is applied to the part of the investment projects financed by regulated entity. Particular system operator has to send the application form to NRA and NRA has to approve. WACC + is applied throughout the project´s lifetime.

SLOVENIA
Summary: • incentives for some transmission investments linked to KPIs • incentive related to voltage quality • efficiency factor for OPEX
Incentives to increase efficiency: When determining operating and maintenance costs, the required increase in cost efficiency is taken into account for each year of the regulatory period, which is reflected in the efficiency factor for each year of the regulatory period. The efficiency factor reflects the requirement for the necessary cost reduction by considering the general productivity of national economy and the individual cost efficiency of the TSO. On the other hand, the individual pre-tax WACC, which is used to calculate the regulated return on assets, is also determined by reference to the individual efficiency of the TSO. The individual cost efficiency of the TSO depends on three efficiency KPIs valuing network utilization, voltage quality and network losses (where network losses due to transit energy flows are not considered). If the TSO reduces the volume of necessary ancillary services in such a way that it is still in line with the requirements of reliable system operation, it is recognised an incentive in the amount of 10% of the value of the provided savings in purchasing this service. If the TSO acquires non-refundable funds for investments (development), it is recognized a one-time incentive in the amount of 6% of the funds acquired in the eligible costs for the year when the related asset was put into use.

Key performance indicators (KPI) to monitor the efficient use of existing infrastructure

(100) In its Position Paper (November 2021), ACER recognised the potential contribution of network key-performance indicators ('KPIs') in measuring the impacts and the benefits of TSO investments and consequently of KPI-based incentives and stressed that some major KPIs could be implemented in all Member States to facilitate harmonised setting of metrics and to allow, to a certain degree, comparable results, taking into account the specificities among the individual Member States.

(101) While the monitoring of the efficient use of existing infrastructure is not in the focus of this ACER Report (except where such KPIs are linked to granting regulatory incentives and are already presented above), it will be subject to future work planned by ACER with the aim to facilitate sharing of best practices. Therefore, ACER has carried out only a preliminary assessment of the relevant national practices in this Report.

(102) ACER finds that for third of the Member States (AT, EE, FR, GR, IE, IT, PT, SI, SE) the NRA reported that it applies some KPIs to monitor the efficient use of existing infrastructure, and some of them are used for the purpose of providing economic incentives. As shown in Table 10 below, such KPIs include level of transfer capacity, unavailability of network elements or interruptions of energy supply, level of grid losses, voltage quality parameters, user satisfaction, etc.

Table 11. Key performance indicators used for the monitoring the efficient use of existing electricity transmission infrastructure

KPI	Countries
Related to market integration, (e.g. transfer capacity between zones, or its unavailability)	IT, AT
Related to unavailability of network elements, system performance, continuity of supply (e.g. SAIDI, SAIFI)	EE, IT, IE, SE
Related to investment costs	IT
Related to costs/volumes of losses or system services	IT, IE, SE, AT
Related to generation curtailments (e.g. RES)	IT, FR
Related to security/continuity of supply (e.g. energy not supplied/withdrawn after interruptions, major outages, number of interruptions/ outages, etc.	IT, AT, SE
Related to the utilization of the grid, transformers (e.g. average load factor)	PT, SE
Voltage quality parameters	IT, FR
Compliance with deadlines and commitments to users (e.g. in connection agreement, meter repair, response to claims, publications, etc.)	FR, AT

Recent, ongoing and planned changes in the national regulatory frameworks:

(103) More than third of the Member States reported changes in process or being considered for the next regulatory period regarding regulatory incentives for investments in network development, such as identification of KPI indicators (IT, GR), monitoring of CAPEX expenses (GR) or ex-post re-evaluation of some investments (CZ), replacement of the system of incentives measures with general CAPEX top up (DE), establishing incentives for projects which incorporate 'innovations' (GR), introduction of WACC adds-on (SK), introduction of an incentive for flexibility services (SE), introduction of a cost-efficiency factor which is taken into account in determining the WACC adjustment (SI), incentives scheme for smart investments (SI) and other under consideration or planned new/different incentive schemes/measures (GR, IE, LV, NL, SE), some of them already reported in previous sections of this Report.

(104) Combined with the information about recent changes in several Member States in the general regulatory framework for recovering CAPEX or OPEX (see Section 4.3), these changes seem to indicate that the regulation of electricity transmission networks are in general evolving in Europe and may require continuous adaptation to the new realities.

(105) In this regard, ACER deems that the regulatory frameworks should provide a stable and predictable basis for investments, but they also require regular revisions and potential adjustments in case they fail to deliver the necessary infrastructures in the most efficient manner.

4. Conclusions

(106) ACER considers that in order to avoid underinvestment or inefficient investment in the electricity transmission network, it is of utmost importance that the investments which bring the highest value for society are identified and implemented and that national regulatory frameworks feature appropriate regulatory measures, including identification of needs for new transmission capacity, project cost-benefit assessment, risk mitigation, fair remuneration and, where necessary, additional incentives.

(107) While Article 17 of the TEN-E Regulation aims at avoiding that European priority projects are not planned or implemented by the project promoters due to high risk for them, ACER's findings show that only in a very few instances during the past ten years higher risks were claimed by the project promoters. Next to that, the implementation of investments in electricity transmission projects, including PCIs, is rarely hindered by project promoters' risks, rather due to permit granting related reasons as shown by ACER's monitoring of the progress of the relevant projects.

(108) Typically, each national regulatory framework provides the same return to all electricity transmission infrastructure projects in the country, irrespective of their individual risk profile or impact. Most Member States apply the Capital Asset Pricing Model ('CAPM'), which focuses on the identification of the level of systematic risk for the overall transmission activity. ACER notes that the parameters for setting the WACC vary across the Member States and the benchmarking with other Member States are important tools in defining or approving the relevant parameters.

(109) ACER finds that the TSOs' risks are generally covered/mitigated in most Member States by the default national regulatory framework. The means of risk coverage or mitigation vary across the

Member States. In the remaining instances, certain risks were deemed marginal in the national context or are intentionally left to be borne by the project promoters (and are not mitigated by the regulatory framework) to incentivise timely and efficient investments.

(110) ACER concludes that the national regulatory frameworks, which systematically mitigate the risks and rarely provide different/beneficial treatment for different projects are generally fit for purpose with respect to risk mitigation and the need for additional project specific incentives has so far been limited, while ACER also acknowledges that the need for such incentives may change over time[155].

(111) In this regard, in ACER's view as long as offshore electricity transmission projects are regulated, no project-specific regulatory risks, financing risks and market risks would actually arise or – in other terms – the same level of risk would generally apply to offshore and to onshore projects. Similarly, offshore anticipatory investments, which are positively assessed by the NRA, do not generally entail higher risks for the TSOs compared to other projects in most Member States, in light of the applied risk mitigation measures.

(112) Regarding the evaluation and treatment of potential higher risks projects, ACER concluded that its common risk identification and assessment methodology and its proposals in ACER Recommendation No 03/2014 on how to mitigate certain TSO's risks (concerning both project specific and general risk mitigation) and/or to provide additional reward for the higher risks, are still valid and applicable, and expected to ensure that that risks to be borne by the project promoters do not become a barrier for the project implementation.

(113) ACER also underlines that the general risk mitigation approach does not guarantee that the most beneficial and cost-efficient investments are put forward. For example, some investments may not be proposed by TSOs despite their higher value for society, because the regulatory frameworks treat all projects alike, while continuous technological advancements are likely to offer more cost-efficient solutions to reach the envisaged benefits/targets[156].

(114) Therefore, in ACER's view, the focus on how to improve the incentives framework should be shifted from the project risk mitigation/compensation transmission system operators to prioritising the identification of more cost-efficient, but currently "missing" solutions/projects.

(115) The needs identification introduced in the TEN-E Regulation (Articles 13 and 14) is an important step for setting the right goals for network development. It foresees that all relevant alternative network development options are considered and favours the most efficient solutions to be prioritised. Given that from the collected information it seems that in many instances this step is not in place or not adequately developed in the national transmission planning frameworks,

[155] E.g. due to evolution of efficiency benchmarks impacting reimbursement of investments, in particular when applying novel technologies with high risks of significant cost overruns.
[156] E.g. where dynamic line-rating can mitigate the need for building new infrastructure.

ACER sees a significant room for improvement by establishing or improving identification of the investment needs by TSOs and their regulatory scrutiny by NRAs.

(116) Furthermore, the assessment of major electricity transmission projects is performed in about half of the Member States, providing at least some monetised indicators, presence of a CBA methodology favours to properly prioritise between proposed projects and among alternatives that could address the same need.

(117) It is also important to ensure that TSOs receive a fair and sufficient remuneration for their investments and face no counterincentives develop the network in the most efficient way, for example the TSOs do not face any bias towards specific solutions.

(118) ACER considers that CAPEX-bias (i.e. preference for CAPEX-intensive solutions due to different remuneration scheme or business interests) is currently a prominent issue in Europe[157], also taking into account that almost half of the Member States apply rate-of-return regulation for CAPEX, which is often combined with incentive regulation for OPEX.

(119) In several Member States the TSOs receive benefit-based incentives (including penalties and rewards) targeting one or more specific objectives, such as cost efficiency, energy efficiency, market integration, security of supply, innovation, RES integration, etc. Additionally, most regulatory frameworks provide incentives (indirectly) by not reducing certain risks for the TSOs (e.g. timely delivery is incentivised by partial mitigation of the risks related to time-overruns).

(120) ACER concludes that except for a few instances, the national regulatory frameworks do not differentiate in any way between investments made in onshore and offshore projects, including based on other project features (such as CAPEX level, interconnection vs. internal line and/or anticipatory investment). Therefore, the benefit-based and other regulatory incentives apply to them on the same terms. In the Member States where a differentiation for offshore projects exists, in two instances it means additional incentives/beneficial treatment and in one instance it means a case-by-case treatment of offshore projects.

[157] ACER Position on incentivising smart investments to improve efficient use of electricity transmission assets, https://acer.europa.eu/Official_documents/Position_Papers/Position%20papers/Position%20Paper%20on%20infrastructure%20efficiency.pdf

5. Recommendations

(121) In line with Article 17(5) ACER makes the following recommendations regarding the (risk-based project specific) incentives and a common methodology to evaluate the incurred higher risks of investments in energy infrastructure projects:

a) In case of TSO's requests for incentives on individual projects, NRAs should use the ACER 7-step common methodology for risk identification and risk assessment described in ACER recommendation No 03/2014, for assessing individual requests for incentives;

b) NRAs should apply project-specific incentives only for projects where the default regulatory framework fails to already provide a fair and sufficient risk/revenue balance;

c) NRAs should follow ACER's previous recommendations regarding risk mitigation measures described in ACER Recommendation No 03/2014, more specifically:

i. Where appropriate, the adjustment for caps (ex-ante or ex-post) for OPEX should be considered for cases where it is proven that an innovative transmission technology, either onshore or offshore, has higher costs for operation and maintenance that cannot be covered by the existing caps. The adjustment of caps for OPEX should also be considered where higher costs are incurred due to unforeseen events beyond the control of the project promoters, which could not be reasonably expected to be revealed by due diligence a priori. The adjustments should be set carefully (e.g. after cost evaluation, including benchmarking of the set of indicators) to avoid burdening network users with the risk of inaccurate cost forecasts, especially concerning proven technologies.

ii. Where the default regulatory framework does not already cover the risk of time-overrun, the NRAs should consider the recognition of efficient costs that may result from time overruns beyond the control of the project promoters.

iii. NRAs should consider the mitigation of the volume risk, where such risk exist and the mitigation is justified, through a regulatory account (e.g. reconciliation of the deficit or surplus in later years by including it in the allowed/target revenues).

iv. Benchmarking and similar measures (unit investment costs) for the identification of efficiently incurred cost are important regulatory tools and ACER recommends NRA to use them. In order to mitigate risks related to identification of efficiently incurred costs, NRAs should aim at ensuring that the specific features based on certain project features (including being a PCI) are reflected in the design of the benchmarking scheme. Where anticipatory investments have been included into the RAB and the connected assets (e.g. power plants) unexpectedly are not built should still be considered efficient.

v. In order to mitigate liquidity risks as far as possible from a regulatory perspective, NRAs should consider allowing revenues based on planned (stages of) expenditure, combined with an ex-post adjustment based on economically efficient real values. Where efficiently incurred expenditures before commissioning of the project are very large compared to the size of the TSO or of the project promoter, NRAs should consider approving them and their inclusion in the Regulatory Asset Base when the expenditure is incurred.

(122) ACER also underlines that the general risk mitigation alone does not guarantee that the most beneficial and the most efficient investments are put forward, because the regulatory frameworks treat all projects alike.

(123) Based on Article 17(4) submissions of NRA methodologies and criteria used to evaluate investments in energy infrastructure projects ACER sees a great room for improvement in the identification of the investment needs by TSOs, in the evaluation of network development options by NRAs and in the application of the CBA methodology in order to select more cost-efficient solutions to reach the envisaged benefits/targets.

(124) For this reason, in accordance with Article 6(2) of the ACER Regulation, ACER provides the following recommendations regarding the evaluation of investment needs and assessment of individual investments:

a) NRAs should ensure that TSOs carry out detailed technical studies for the identification of the investment needs as well as that substantial public consultation takes place, and the necessary transparency for inclusive participation is ensured by making all relevant information (including the network and market datasets used for the studies) available to stakeholders.

b) NRAs should evaluate the investment gaps identified by TSOs or other stakeholders and identify if there are additional investment gaps. For this purpose, NRAs should take into account at least the TSO's detailed technical study and the results of the public consultation;

c) NRAs should establish and request TSOs to use a cost benefit analysis (CBA) methodology and pursue the monetisation (to the extent possible) of the most relevant project benefits (including, among others, market integration, variation of losses, security of supply and sustainability/climate benefits), at least for the assessment of high CAPEX projects, in order to prioritise between individual projects and among alternatives that could address the same need;

(125) Further, to foster development of efficient networks (both onshore and offshore) ACER provides the following recommendations regarding fair risk/revenue balance, benefit-based incentives and related indicators:

a) NRAs should ensure that transmission system operators receive a fair and sufficient remuneration for their investments and face no counterincentives to most efficiently develop the network. Where NRAs conclude that CAPEX-bias is present in the regulatory framework, NRAs should primarily mitigate it with total-expenditure (TOTEX) regulation to incentivise more cost-efficient solutions among alternatives which address the same investment need.

b) When setting or approving the parameters used for establishing the Weighted Average Cost of Capital (WACC), NRAs should compare the relevant values (like market related risk) with values used in other EU Member States and justify if they decide to use an outlier value.

c) NRAs should provide appropriate incentives to ensure that the investment gaps are addressed the most efficiently; if the regulatory tools currently in place providing a fair risk/revenue balance are insufficient to achieve it, NRAs should apply benefit-based incentives in a systematic way (i.e. not only upon request for individual projects) linked directly to the measurable project benefits or major performance targets, set in a way to ensure the investment's value to the network user (i.e. decreasing the overall electricity costs).

d) NRAs should define ex-ante the rules and parameters of such incentives to avoid any potential dispute and to allow predicting economic impacts and, as far as feasible, avoid exogenous parameters impacting the results. For benefit-based incentives, part of the monetised benefits an investment brings to society could be shared ex-post with the TSO. Finally, such incentives should be reassessed over time and the newly achieved performance, once structurally achieved, should become a standard expectation, at which time the benefit sharing would be discontinued.

e) NRAs should define and if deemed appropriate, implement major performance indicators for monitoring the efficient use of existing infrastructure. Such performance indicators may be also linked to benefit-based incentives.

Annex – NRA submissions of information regarding the particular aspects of the national regulatory frameworks for electricity infrastructure projects reviewed for the purpose of this report (excel table).