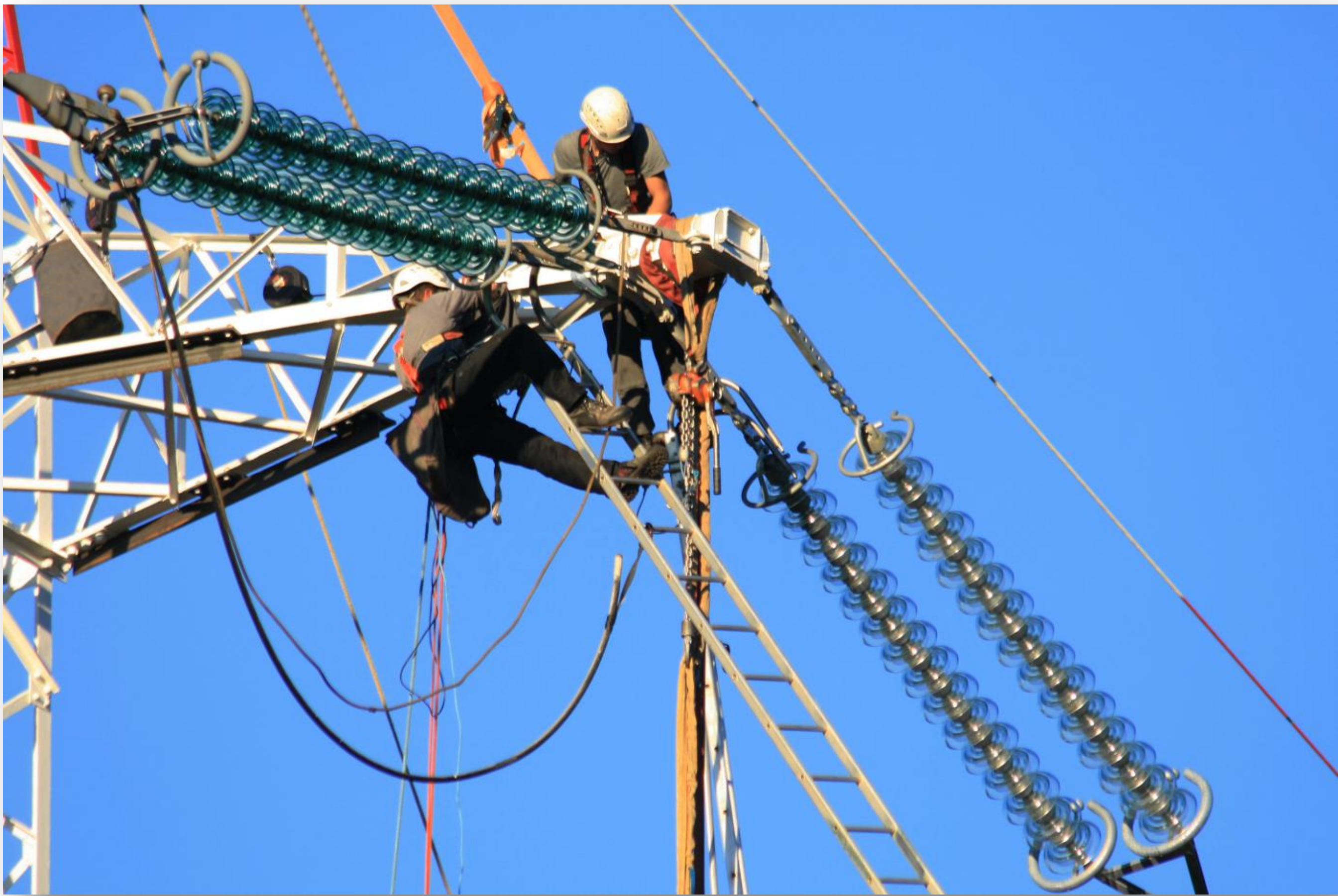

RISK – RELATED REGULATORY INVESTMENT INCENTIVES FOR PROJECTS OF ENERGY COMMUNITY INTEREST

A Recommendation Paper

April 2015

CONTENTS

List of abbreviations

CAPM	capital asset pricing model
CBA	cost- benefit analysis
CBCA	cross- border cost allocation
CEF	Connecting Europe Facility
CWIP	construction work in progress
EC	European Commission
ECS	Energy Community Secretariat
ECRB	Energy Community Regulatory Board
EnC	Energy Community
ERP	equity risk premium (market risk premium)
EU MS	European Union member state
IFI	International Financing Institution
NRA	national regulatory authority
PCI	Projects of Common Interest
PECI	Projects of Energy Community interest
PHLG	Permanent High Level Group
RAB	regulatory asset base
RIP	Regional Investment Plan
RoR	rate of return
TSO	transmission system operator
TYNDP	Ten Year Network Development Plan
WACC	weighted average cost of capital

Related documents

ECRB documents

[1]. Status Review of Main Criteria for Allowed Revenue Determination, 18 December 2013

[2]. ECRB Position on regulatory investment incentives, 04 Jun 2013

[3]. Cooperation of Regulators with Regard to Cross Border Investment Projects, 16 March 2010

[4]. Regulatory Framework for development of the Energy Community Gas Ring, 16 March 2010

External documents

[5]. Recommendation on incentives for projects of common interest and on a common methodology for risk evaluation, ACER, 27 June 2014

[6]. REGULATION (EU) No 347/2013 OF THE EUROPEAN PARLIAMENT AND OF THE COUNCIL of 17 April 2013 on guidelines for trans-European energy infrastructure and repealing Decision No 1364/2006/EC and amending Regulations (EC) No 713/2009, (EC) No 714/2009 and (EC) No 715/2009

[7]. Commission Staff Working Paper: Impact assessment Accompanying the Document Proposal for a Regulation of the European Parliament and of the Council on Guidelines for trans- European Energy Infrastructure and Repealing Decision No 1364/2006 /EC SEC/2011/1233 final, 19 October 2011

[8]. Energy Strategy of the Energy Community, Energy Community, 09 July 2013

[9]. Energy Community Strategy and Projects of Energy Community Interest, ECS, 12 November 2013

[10]. Development of Best Practice Recommendations on Regulatory Incentives Promoting Infrastructure Investment, E- Bridge, November 2011

[11]. Recommendations for Funding Investment in the Energy Community Gas Ring, Energy Market Insights, 31 December 2011

[12]. The Structuring and Financing of Energy Infrastructure Projects, Financing gaps and recommendations Regarding the new TEN-E financial instrument, Roland Berger, 31 July 2011

[13]. Improving Incentives for Investment in Electricity Transmission Infrastructure, Frontier Economics & Consentec, November 2008

[14]. Promoting Transmission Investment through Pricing Reform, Order No. 679, FERC, 20 July 2006

I. Introduction

1. About ECRB

The Energy Community Regulatory Board (ECRB) operates based on the Treaty Establishing the Energy Community. As an institution of the Energy Community [1] the ECRB advises the Energy Community Ministerial Council and Permanent High Level Group on details of statutory, technical and regulatory rules and makes recommendations in the case of cross-border disputes between regulators[2]. The ECRB may also take Measures[3], if so empowered by the Ministerial Council.

ECRB is the independent regional voice of energy regulators in the Energy Community and beyond. ECRB's mission builds on three pillars: providing coordinated regulatory positions to energy policy debates, harmonizing regulatory rules across borders and sharing regulatory knowledge and experience.

2. Background

2.1. EU Policy Context - the Infrastructure Package and Projects of Common Interest

On 17th April 2013 the European Parliament and the Council adopted Regulation (EC) No 347/2013 on guidelines for trans-European energy infrastructure (hereinafter "TEN-E Regulation") with the view to set an optimal framework for developing sufficient infrastructure supporting the EU efforts to meet its energy and climate policy goals. The TEN-E Regulation sets common principles for identification of projects of common interest (PCI) based on the Union-wide TYNDP, defines broad criteria for identification of PCI, sets measures for acceleration of permitting procedures for PCI, enhances the regulatory treatment of PCI by enabling investments with cross-border impacts via CBCA[4] and empowering NRA for granting specific risk-related incentives for PCI and establishes rules for granting EU financial support to PCI. The TEN-E Regulation has been supplemented with new financial instruments facilitating access to long term financing of eligible PCI by providing debt facilities (e.g. the Project Bond Initiative) or injecting equity (e.g. the Connecting Europe Facility[5],CEF) into projects.

On 14th October 2013, the EC adopted a list of 248 key energy infrastructure projects[6], selected by twelve regional groups established by the TEN-E Regulation. This PCI list includes also third countries' projects, among others such involving Energy Community Contracting Parties (Albania, Bosnia and Herzegovina,

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[1] www.energy-community.org. The Energy Community comprises the EU and Albania, Bosnia and Herzegovina, Macedonia, Kosovo*, Moldova, Montenegro, Serbia and Ukraine. Armenia, Georgia, Turkey and Norway are Observer Countries. [**Throughout this document the symbol * refers to the following statement: This designation is without prejudice to positions on status, and is in line with UNSCR 1244 and the ICJ Opinion on the Kosovo declaration of independence*].

[2] The work of the ECRB is supported by the ECRB Section at the Energy Community Secretariat.

[3] According to Article 76 of the Treaty Establishing the Energy Community, "Measures may take the form of a Decision or a Recommendation. A Decision is legally binding in its entirety upon those to whom it is addressed. A Recommendation has no binding force. Parties shall use their best endeavors to carry out Recommendations."

[4] Allocating costs across borders proportionally to the benefits provided.

[5] Regulation (EU) No 1316/2013 of The European Parliament and of the Council of 11 December 2013 establishing the Connecting Europe Facility, amending Regulation (EU) No 913/2010 and repealing Regulations (EC) No 680/2007 and (EC) No 67/2010.

[6] COMMISSION DELEGATED REGULATION (EU) No 1391/2013 of 14 October 2013 amending Regulation (EU) No 347/2013 of the European Parliament and of the Council on guidelines for trans-European energy infrastructure as regards the Union list of projects of common interest. The updated list is available at http://ec.europa.eu/energy/infrastructure/pci/doc/2013_pci_projects_country.pdf.

Montenegro, Serbia and Ukraine). In October 2014, €647 million has been granted[7] under the CEF to 34 eligible projects from the 2013 PCI list. The second PCI list is expected to be adopted in 2015, based on inputs provided within ENTSO-E and ENTSO-G TYNDPs (both Union-wide TYNDP will include the results of CBA).

In line with its obligations stemming from the TEN-E Regulation, ACER adopted a Recommendation regarding CBCA requests[8] (September 2013), as well as the Recommendation on incentives for PCI and on a common methodology for risk evaluation[9] (June 2014), establishing thereby common elements for EU NRA deliberations on CBCA requests and regulatory incentives for PCI respectively. On 11th August 2014 ACER adopted its first decision on CBCA, more specifically, on allocation of costs for the gas interconnection project between Poland and Lithuania.

2.2. The Energy Community policy context - Projects of Energy Community Interest

On 6th October 2011, recognizing the need to introduce certain top-down guidance in functioning of the Energy Community by defining priority objectives for the future and appropriate actions to be taken, the Ministerial Council of the Energy Community approved the establishment of a Regional Energy Strategy Task Force (hereinafter: Strategy TF) mandated to *"elaborate a Regional Energy Strategy, including a special part on Regional Power Development and Investment Plan aiming at promoting investments."*[10] On 18th October 2012 the Energy Community Ministerial Council endorsed the Energy Strategy of the Energy Community[11] (hereinafter: the Strategy). The Strategy establishes the concept of PECI and sets the bases for defining the methodology and criteria for their identification, whereby an effort has been made to achieve their compatibility with EU developments (draft TEN-E regulation, activities on establishing the PCI list).

After finalization of the Strategy, based on the extension of its mandate provided by the 10th Ministerial Council[12], the Strategy TF - (chaired by the EC and supported by the ECS and an external consultant- finalized the methodology[13] outlined by the Strategy and prepared a draft list of PECI. After PHLG review and public consultation, on its meeting of 24th October 2013[14] the Ministerial Council adopted the final list of PECI[15]. At the same meeting, based on the ECRB recommendation[16] of 4th June 2013, the Ministerial Council invited EC and ECS to prepare proposals for adoption of certain provisions of the TEN-E regulation applicable to the Energy Community.

In the conclusions[17] of its 33rd meeting of 18th June 2014, the PHLG requested full incorporation of Regulation (EC) 347/2013 into the Energy Community acquis at the Ministerial Council meeting in 2015. It welcomed the proposal to focus, in the meantime, on a project-by-project approach where a list of elements

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[7] EC decision on the list of actions and amounts granted, formalizing EU MS voting, is expected to follow.
[8] Recommendation of the Agency for the Cooperation of Energy Regulators No 07/2013 of 25 September 2013 regarding the cross-border cost allocation requests submitted in the framework of the first Union list of electricity and gas Projects of Common Interest.
[9] Recommendation of the Agency for the Cooperation of Energy Regulators No 03/2014 of 27 June 2014 on incentives for Projects of Common Interest and on a common methodology for risk evaluation.
[10] 9th Energy Community Ministerial Council, Chisinau, 6th October 2011, Meeting Conclusions.
[11] http://www.energy-community.org/pls/portal/docs/1810178.PDF.
[12] 10th Energy Community Ministerial Council, Budva, 18th October 2012, Meeting Conclusions.
[13] DNV KEMA / REKK /IHP: Development and Application of a Methodology to Identify PECI (November 2013).
[14] 11th Energy Community Ministerial Council Meeting, Belgrade, 24th October 2013, Meeting Conclusions
[15] http://www.energy-community.org/portal/page/portal/ENC_HOME/AREAS_OF_WORK/Investments/PECIs/List_PECI.
[16] Minutes of the 24th ECRB Meeting, 4th June 2013, Athens.
[17] Conclusions of the 33rd PHLG meeting, Vienna, 18th June 2014.

of an improved administrative and regulatory governance, including those from Regulation (EC) 347/2013, would be identified and made binding for each individual PECI. As a follow- up, the EnC Ministerial Council on its meeting of 23rd September 2014 adopted a Recommendation on Guidelines for Trans-European Energy Infrastructure[18], paving the way for implementation of the TEN-E Regulation in the EnC regulatory framework in late 2015. The Recommendation also specifies several activities to be undertaken before TEN-E Regulation enters into force in the EnC Contracting Parties, with an objective to facilitate the early implementation of PECI:

- By 31 March 2015, each Contracting Party identifies in a report financial, administrative and regulatory barriers for implementation of the Projects of Energy Community Interest (in energy infrastructure categories) or Projects of Common Interest on the territory of their jurisdiction.
- By the same date, each Contracting Party provides the Secretariat with a list of most relevant measures, including Articles of Regulation (EU) No 347/2013 which would address the identified barriers. The list should be accompanied by an impact assessment for each element.
- On the basis of the contributions of the Contracting Parties the Secretariat and the Commission prepare an analytical report establishing measures including Articles of the Regulation (EU) No 347/2013 which would require fastest implementation into the national legislations to allow progress with the realization of Projects of Energy Community Interest and Projects of Common Interest respectively, by 31 May 2015.
- The PHLG adopts on its June meeting in 2015 a list of priority measures, including Articles of the Regulation (EU) No 347/2013 to be implemented by each Contracting Party in national legislation.
- ECRB engages in a discussion with ACER on how to approach regulatory cooperation for projects across borders between Contracting Parties and Member States.

ECRB notes that **several issues remain to be resolved by the EnC institutions** in order to establish a sustainable regional mechanism supporting infrastructure investments in the region, either through implementation of the TEN-E Regulation or by other means:

- **The dynamics of adjustment of the PECI list: currently it is not clear if and when the PECI list will be reviewed; in EU the PCI list is renewed in intervals of two years.**
- **Treatment of the electricity generation projects in the second PECI list.**
- **Treatment of CBA: the mechanism used for the PECI list differs from the one used by ENTSOs,** which may be problem in case of a request for CBCA between a Contracting Party and EU MS; in this context it has to be noted that CBA in line with the ENTSO methodology is used as input for CBCA decisions.
- **Identifying applicable debt and equity financing sources/mechanisms for PECI.**

2.3. Purpose and Objectives

The ongoing process of identifying PECI and facilitating their implementation in the EnC Contracting Parties is mirroring the EU framework on PCI. Figure 1 presents a comparison of current status of development of the mechanisms facilitating P(E)CI in EU and EnC, explained in more details in 2.1 and 2.2).

[18] Recommendation of the Ministerial Council of the Energy Community No. 2014/01/MC-EnC of 23 September 2014 on Guidelines for Trans-European Energy Infrastructure.

The for 2015 envisaged transposition of the TEN-E Regulation in EnC acquis , together with other complementary actions on national and EnC level, will contribute to further aligning the regulatory frameworks of the EnC Contracting Parties and EU MS, establishing a set of measures aimed to accelerate the permitting procedures, enhancing the regulatory treatment of PECI and, ideally, providing for innovative mechanisms for access to debt and equity financing.

However, the ECRB considers it necessary to elaborate certain aspects of the regulatory treatment of PECI in this recommendation paper *even before* the implementation of the TEN-E Regulation in the EnC, with a view to support early implementation of regulatory investment incentives to PECI by NRAs, where deemed necessary.

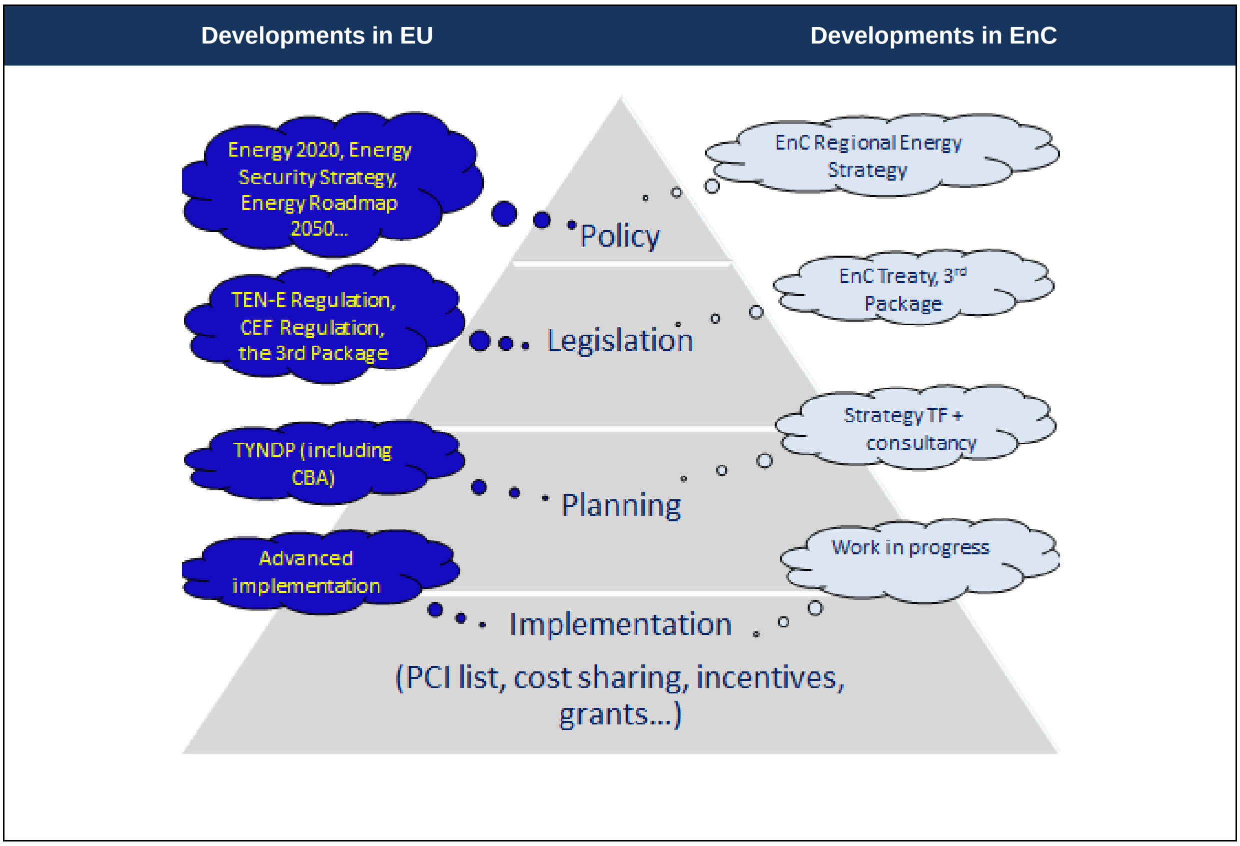

Figure 1: P(E)CI- status in EU and EnC

3. Methodology

At its meeting of 15th April 2014, the ECRB decided to develop a toolbox on regulatory investment incentives to be used by the NRA depending on national specificities and a common methodology for project risk evaluation.

The analysis provided in the present recommendation paper is based on the "Recommendation on incentives for PCI and on a common methodology for risk evaluation"[19] **developed by ACER** for the same purpose, namely- *"to develop a general framework for incentives for promoters of PCIs who are incurring higher risks than for comparable projects"*[20]. Efforts have been made to align the structure, content and depth of analysis with the ACER approach, while simultaneously taking on board the specificities of the institutional structure, legal framework and applicable regulatory mechanisms - both on national, i.e. Contracting Parties', and Energy Community level - by strong reliance on previous work of ECRB. Where deemed necessary external sources have also been used.

Although the PECI list includes also electricity generation projects[21], this recommendation paper does not provide any guidance on investment incentives for such projects. **ECRB recognizes that the issue of generation adequacy and investment climate for PECI generation projects deserves utmost attention**, especially in context of current discussions in EU, but leaves it for further investigation, pending on the decision of the EnC institutions on establishing a sustainable mechanism for identification and support of PECI generation projects.

Furthermore, although the magnitude and type of risks may vary significantly among the Contracting Parties, national barriers for investments have not been investigated and presented in this paper. ECRB emphasizes that a **thorough knowledge of type and impact of nationally specific barriers for infrastructure investments is a precondition for identifying a need for additional incentives and implementing them in a proportional way.** In certain jurisdictions, enhancing the permitting procedures or accessibility to equity and debt financing may be sufficient to mitigate the national investment barriers (i.e. dedicated investment incentives may not be necessary). In this context, in addition to the recommendations of ECRB provided in this paper and ACER recommendations[18], NRAs should pay utmost attention to the **Contracting Parties reports on financial, administrative and regulatory barriers for implementation of PECI** or PCI on the territory of their jurisdiction[22].

Chapter II of this recommendation paper presents national practices of risk evaluation in the EnC Contracting Parties and provides recommendation on a common methodology for risk identification. Chapter III provides a status review of applicable investment incentives in the Contracting Parties, highlights critical barriers for introducing investment incentives and presents a toolbox which may be used by NRAs to define applicable investment incentives.

[19] Recommendation of the Agency for the Cooperation of Energy Regulators No 03/2014 of 27 June 2014 on incentives for Projects of Common Interest and on a common methodology for risk evaluation.
[20] Ref. fn 18.
[21] This is not the case with the PCI list.
[22] According to the Recommendation of the Ministerial Council of the Energy Community No. 2014/01/MC-EnC of 23 September 2014 on Guidelines for Trans-European Energy Infrastructure, such reports are to be finalized until 31 March 2015.

II. PECI Risk Identification and Assessment

It is widely recognized that the general "financial climate" for energy networks infrastructure projects,i.e. their financial viability, is significantly influenced by the applicable regulatory framework. Being subject of price regulation, electricity and natural gas transmission companies reimburse their capital and operational expenditures based on pricing mechanisms (price controls) developed by the NRA. Normally, well-designed price controls should ensure recovery of all prudently incurred costs, including investment projects costs, taking into consideration at least the **average systematic risk of the TSO's investment portfolio** via the regulator's estimate of the cost of capital (more precisely, equity risk premium, usually using firm's beta[23]), but also **other risks** depending on the features of the applied model of price regulation. ECRB recognizes that the PECI promoters may be exposed to additional non-controllable risks that were not observed or accounted for by the NRA while setting the price controls, and that such risks may adversely influence both the project promoter's decision to invest and the lenders perception of the bankability of the project.

1. Summary of National Practices Regarding Risk Evaluation in Energy Community Contracting Parties

Based on the findings of the recent ECRB status review on pricing of regulated activities[24], it may be concluded that the NRAs of the Region[25] compensate for the systematic risk of the overall transmission activity (e.g. the complete infrastructure project portfolio) within the price controls applied, either using CAPM or other methods.

Any project-specific risk evaluation practices targeting to identify or evaluate higher risks -either systematic or diversifiable - faced by PECI (or other) transmission project promoters have not been reported or identified.

Approximately half of the examined NRAs reported using CAPM formula[26] for evaluating the cost of equity. This is a clear difference in comparison with EU MS regulatory frameworks[27] where - with few exceptions - CAPM is applied. Namely, the immaturity of the Contracting Parties' capital markets brings additional complexity in assessing ERP (lack of reliable historical data necessary to assess expected market returns- r_m) and betas (lack of historical data on market returns and TSOs' stock yields, excluding regression analysis and pure play method[28] as means to assess equity beta). For this reason, Contracting Parties' NRAs opt

[23] Beta indicates the relative riskiness of the company with respect to non-diversifiable risk by measuring underlying business risk (asset beta) and financial risk arising from debt- equity structure. It compares company's (TSO's) returns in relation to returns on investment in diversified portfolio of equity holdings.
[24] ECRB, "Status Review of Main Criteria for Allowed Revenue Determination for transmission, distribution and regulated supply of electricity and gas" (December 2013). Results of the status review for electricity and natural gas transmission are summarized in Annex I.
[25] The report covers Albania, Bosnia and Herzegovina, Croatia, Former Yugoslav Republic of Macedonia, Georgia, Kosovo*, Moldova, Montenegro, Serbia, Turkey and Ukraine.
[26] $r_e = r_f + \beta \times (r_m - r_f)$; r_e- cost of equity; r_f- risk free rate; r_m- market return; ERP=$(r_m - r_f)$- market risk premium.
[27] Ref. Recommendation of the Agency for the Cooperation of Energy Regulators No 03/2014 of 27 June 2014 on incentives for Projects of Common Interest and on a common methodology for risk evaluation.
[28] Pure play method is used to derive equity beta from asset beta for companies that are not publicly traded.

either for alternative methods of WACC calculation, or using proxies[29] based on international benchmarking or (more or less) arbitrary assumptions as inputs to the CAPM formula instead of national market data.

As all Contracting Parties NRA do not apply CAPM, and those who do assess input values for the CAPM formula using proxies or arbitrary assumptions, the level of integration of systematic risks could not be observed using comparison of betas and ERP for each Contracting Party as an indication. However, certain conclusions could be derived by analysis of WACC data (provided by all NRAs). The resulting WACC levels in the electricity sector range from 0,67% in Bosnia and Herzegovina to 8,95% in Moldova for electricity transmission and from 1,8% in Bosnia and Herzegovina to 12,23% in Moldova for natural gas transmission. Such diversity of WACC values may raise doubt if the allowed cost of capital set by the NRA commensurate to the returns expected by debt and equity providers, i.e. if the reimbursement for the risks incurred fully covers the systematic risks (but also the time value of money) in all cases.

2. Common methodology for risk identification and assessment for PECI

The purpose of the following "Methodology for risk identification and assessment for PECI" is to set a common basis for the Contracting Parties NRAs to assess:

- the portfolio[30] risk profile of the TSO or project promoter, as a basis for granting portfolio-based regulatory incentives - applicable also to PECI - in case that assessed risk is higher in comparison with those accounted for in price controls
- the risk profile of a specific project as an input for granting (PECI) project-specific regulatory incentives in case that assessed risk is higher compared to the risks normally incurred by a comparable infrastructure project

Due to the reasons explained in III. 4.1identification of the project-specific PECI risks and granting project-specific incentives (on case-by-case bases) by Contracting Parties' NRA would be extremely difficult (if not impossible) to achieve before establishing the appropriate framework, i.e. transposing TEN-E Regulation in the Energy Community acquis and resolving the uncertainties related to coordinated infrastructure planning - i.e. using the ENTSO-s mechanisms for network development and CBA, or separate instruments like was the case while establishing the first PECI list.

ECRB proposes the following approach to risk identification and assessment to the Contracting Parties NRAs:

- using a transitional methodology for TSO's portfolio risk identification[31] and assessment until implementation of the TEN-E Regulation in the Energy Community law[32] (see III.2.1), which **follows the ACER methodology to the extent possible** and

[29] Although widely used (also by EU NRA), such approach has its intrinsic drawbacks (e.g. input timeframes used for calculation of "provided" betas most probably do not commensurate required time horizons; betas calculated for other- foreign – markets do not accurately reflect the risks of the national market).
[30] This may relate either to the whole portfolio, or to a portfolio of eligible projects, including PECI.
[31] It should be noted that a number of EU NRAs introduced incentives for a portfolio of projects (i.e. applicable to all infrastructure investments or a group of eligible investments) before entry into force of the infrastructure package in 2013).
[32] On its meeting of 23rd September 2013, the Energy Community Ministerial Council decided to implement the TEN-E Regulation in the Energy Community legal framework (Recommendation of the Ministerial Council of the Energy Community No. 2014/01/MC-EnC of 23 September 2014 on Guidelines for Trans-European Energy Infrastructure).

- using the ACER risk evaluation methodology developed by ACER in line with Article 13.5 of the TEN-E Regulation (, once the TEN-E Regulation is implemented by the Energy Community Contracting Parties.

2.1. Transitional methodology for risk identification and assessment

ECRB considers that the process of identification and assessment of TSOs project portfolio should include the following steps:

Step 1: Availability of information on project portfolio risks

ECRB considers the national development plans as valuable sources of information on infrastructure projects, including risks. Developing national-wide TYNDP by the TSO and its approval by the NRA is an obligation introduced by the 3rd Package, which has to be implemented into the Energy Community Contracting Parties' legislation until1st January 2015. ECRB recommends NRAs to **establish and publish pre-defined criteria for TYNDP evaluation and approval** while ensuring compliance of the existing planning procedures with the requirements of the 3rd Package.

Furthermore, the NRAs might find it appropriate to **embed the information required to assess TSOs risk exposure in the mandatory content (or supporting documents) of the national network development plans (TYNDP)**. Such information may include:

- TSO's assessment of risks incurred, demonstrating that they are higher than those accounted for in the price controls (via return on equity or other features of the pricing methodology), where applicable. This assessment may, where appropriate, include quantitative assessment of the impact and probability of the event.
- Proof that the projects bring benefits in terms of competition, security of supply and environmental impact of the sector in comparison with status quo and alternative options; where applicable (members of ENTSO-E), the results of a cost-benefit analysis in accordance with the TEN-E Regulation can be used.

Furthermore, the review of the Contracting Parties' national practices[33] shows a lack of transparency in setting the WACC, i.e. it is not always possible to observe a straightforward relation between the approved WACC and the underlying systematic (non-diversifiable) risks, even where the NRAs reported using CAPM. Therefore the NRAs are advised to **develop detailed calculation algorithms[34] for determination of WACC** (as a part of applicable pricing methodologies or operational procedures for their implementation), perform a public consultation on the proposed mechanisms (in order to take on board opinions of the project promoters[35]) and publish the approved mechanisms. By increasing transparency, the room for arbitrary decisions on cost of capital would be diminished, reducing thereby also the risk of regulatory capture by political institutions or industry.

[33] ECRB, "Status Review of Main Criteria for Allowed Revenue Determination for transmission, distribution and regulated supply of electricity and gas" (December 2013).
[34] E.g. specifying details on and determination of beta, risk free rate, market return etc. and data sources for this purpose.
[35] As highlighted in the ACER Recommendation, "project promoters are best informed about the project's features and aspects".

Step 2: Identification of the nature of risks from a regulatory point of view

ECRB recommends using the categorization of project risks proposed by ACER (ref. Annex III for more details):

- Technical risks
    - The risk of cost overruns
    - The risk of time overruns
- Volume risks (risk of stranded assets)
- Regulatory risks (including risks related to identification of efficiently incurred costs)
- Liquidity risks

Step 3: Risk mitigation measures by TSOs (project promoters)

ECRB considers it necessary that TSOs demonstrate that appropriate risk management mechanisms are embedded in their operational procedures and applied in practice for the projects included in the TYNDP. The NRAs should assess if controllable risks have been facilitated by the TSOs in the most efficient way.

Step 4: Assessment of systematic risk and definition of cost of capital

As discussed above, price controls in majority of jurisdictions, including the Contracting Parties, are aimed to account for the average risk for the whole transmission activity. Due to the fact that both the systematic risks (incorporating market risk and financial risk, if measured by beta) and non-systematic risks vary with time, there is a clear rationale to periodically review risk estimations embedded in the pricing mechanisms in order to avoid under-recovery or over-recovery of project promoters' costs. While considering introduction of regulatory investment incentives, **the NRAs are advised to review if the applied WACC includes market value weights for equity and debt, recognizing reasonable expectations of equity and debt providers to be compensated for the systematic risks assumed.** In other words, the NRAs may find it appropriate to check the adequacy of applied assumptions and data used for calculation of risk free rate, beta, market risk and debt premium before applying incentives. If cost-reflective network tariffs are an issue in certain jurisdictions, investment incentives should not be used as compensation for non-accounted for cost of capital.

Step 5: Risk mitigation measures already applied by NRAs

The TSO's risk profile is influenced by highly complex interdependencies of various features of the regulatory framework such as the applied model of price regulation (high powered- low powered), treatment of the difference between allowed and actual revenues (correction factor, regulatory accounts), treatment of RAB (e.g. asset valuation, including/excluding working capital, including/excluding CWIP etc.), methodology for WACC calculation, treatment of depreciation (straight line, accelerated, assets lifetime), calculation of the efficiency targets (X – factor) in incentive based models, treatment of quality of service etc. **The NRAs are advised to assess if the proposed investment incentives are targeting risks already addressed by the existing price controls.**

III. Regulatory Investment Incentives

1. Summary of national practices regarding risk mitigation, regulatory measures and monetary reward or penalty schemes

1.1. Risk mitigation through the overall national regulatory framework

In the analysed markets rate-of-return, price cap and revenue cap regulation are implemented. Rate- of-return regulation is normally performed on yearly basis[36], while in the case of incentive based regulation the revenues or prices are capped for different periods, namely three or five years.

In electricity the following regulatory systems are applied:

- Rate-of-return regulation in four jurisdictions (Bosnia and Herzegovina, Croatia, Serbia, Ukraine);
- Revenue cap in four jurisdictions (FYR of Macedonia, Kosovo*, Moldova, Montenegro);
- Price cap in one jurisdiction (Albania).

In natural gas the following regulatory systems are applied:

- Rate-of-return regulation in four jurisdictions (Bosnia and Herzegovina, Georgia, Serbia and Ukraine);
- Revenue cap in three jurisdictions (Croatia, FYR of Macedonia, Moldova).

1.2. Risk mitigation through specific regulatory measures

This sub-chapter summarizes information provided in the paper "Cooperation of Regulators with Regard to Cross Border Investment Projects" [37] (ECRB, 2010), responses to the questionnaire on regulatory investment incentives[38] (ECS, 2013) and "Status Review of Main Criteria for Allowed Revenue Determination" [39] (ECRB, 2013).

Specific regulatory incentives tailored for PECI have not been reported. However, in few jurisdictions regulatory investment incentives targeting all investments or a group of investments selected by certain criteria (e.g. new investments) have been established:

- **Monetary reward or penalty schemes:** FYR of Macedonia (higher rate of return for new investments);
- **Rules for anticipatory investments:** FYR of Macedonia and Moldova (investment costs for electricity and natural gas transmission projects covered in the RAB, if part of national investment plan approved by NRA);

[36] This however does not mean that tariffs are necessarily changed every year, but that the calculation base is one year. Tariffs are changed on the request of regulated company or when regulator concludes that basic parameters for allowed revenue and tariff calculation have been changed.
[37] ECRB, "Cooperation of Regulators with Regard to Cross Border Investment Projects" (2010).
[38] ECS, Questionnaire on regulatory investment incentives, 2013; see Annex III of this recommendation paper.
[39] ECRB, "Status Review of Main Criteria for Allowed Revenue Determination for transmission, distribution and regulated supply of electricity and gas" (December 2013).

- **Rules for recognition of efficiently incurred costs before commissioning the project:**
  - Montenegro electricity transmission: the assets under construction are included in the RAB as a tool for incentivizing investments. For the first year of the three year regulatory period the costs related to construction in progress at the end of the previous year are included, for the second year the sum of construction in progress costs for the previous two years and for the third year the sum of construction in progress costs for the previous three years. However, if during a year an investment is realized with a value less than 50% of the value approved for that year, the regulator excludes the total value of the relevant investment as well as relevant depreciation from the RAB until the asset is put in operation. If an investment, whose implementation is planned for the period of three or more years, is realized during the first two years by less than 50% of the plan for the relevant period, the total investment is excluded from the basis for calculation of depreciation and return until put into operation);
  - FYR of Macedonia natural gas transmission: the assets under construction are included in the RAB as a tool for incentivizing investments;
- **Negative incentives (revenues used for tariff reduction if not re-invested):** FYR of Macedonia;
- **Capacity extension agreements:** FYR of Macedonia (electricity and natural gas transmission);

2. Challenges for introduction of regulatory infrastructure investments incentives in the Energy Community Contracting Parties

2.1. Performance of the national regulatory authorities

There is a wide spread view among TSOs and equity and debt providers that regulatory risks, especially those related to the performance of NRAs (e.g. predictability of regulatory regimes, remuneration of incurred costs etc.) are among the most critical challenges for financing infrastructure projects throughout Europe. Various sources identify the regulatory risks as a barrier for investment in infrastructure which is particularly present in the Energy Community Contracting Parties. The EnC Strategy[40] highlights cost-reflectivity of electricity and natural gas tariffs as a key investment barrier. EURELECTRIC[41] emphasized unstable and unpredictable regulation in the region as *"the single most important risk, well above the financial risks. And regulatory instability has also been indicated by those companies not present in the region as the single most important factor preventing them from engagement."* ECS[42] assessed that *"the independence of national energy regulators is threatened by structural measures such as reducing staff, budget or salaries but is also subject to direct political intervention."*

ECRB acknowledges that the sub-optimal performance of the "default" national regulatory framework due to compromised regulatory independence or other reasons, where identified, does not only adversely influence financial viability of PECI, but also the sustainability of the electricity and natural gas industries. ECRB considers that, in jurisdictions where this problem is identified, **expedite full implementation of the**

[40] http://www.energy-community.org/pls/portal/docs/1810178.PDF.
[41] Eurelectric, "Europe's 8th Region: Securing Investments in the Energy Community" (2014).
[42] ECS, "Annual Implementation Report of the Acquis under the Treaty Establishing the Energy Community", (2014).

provisions of Directives 2009/72/EC and 2009/73/EC related to NRA independence[43] **has to be enforced by national and, if necessary, Energy Community institutions**. In addition to this, a thorough assessment and, where necessary, mitigation of potential deficiencies of the "default" regulatory framework should be performed as a prerequisite for introducing regulatory investment incentives for PECI (as discussed earlier, there is no sense in introducing incentives where the prices are not cost-reflective).

2.2. Asymmetric benefits

Asymmetry in distribution of an interconnection project's costs and benefits across borders might be significant, leaving majority of costs on one side of the border, and majority of benefits on the other. Taking into consideration that implementation of the adapted TEN-E Regulation addresses this problem by establishing the CBCA mechanism (ref. Article 12 leg cit), in this paper ECRB highlights existence of this barrier for investment, and emphasizes the need that seamless application of the CBCA mechanism across the geographic scope of the Energy Community has to be ensured both in electricity and natural gas sectors (e.g. participation of Contracting Parties in ENTSOs planning process including CBA, establishment of a procedure applicable in case NRAs cannot make an agreement on CBCA etc.).

3. A toolbox on regulatory investment incentives

3.1. The rules for anticipatory investment

The rules for anticipatory investment are deemed to mitigate the volume risk (risk of stranded assets), which arises from the so called **advance capacity challenge**, occurring where the financial viability of an investment is conditional on finalization of another infrastructure project(s) in the electricity/natural gas value chain (e.g. phased development of electricity generation or natural gas production capacity to be connected to the transmission network; natural gas pipelines where future capacity requirements are clear but the timing for the build-up of the capacity demand remains uncertain). In this case the investment realized by TSO would represent sunk cost that has to be borne by all network users. Therefore, if building facilities capable of handling more capacity than exists at present is cheaper than upgrading such facilities in the future, it may be justified to support such projects so that greater capacity can be planned, built and financed even though full utilization may only be achieved at a later point in time. This paper identifies two ways of facilitating the advance capacity challenge- via **price controls** set by the NRA and via **network users' financial commitment**.

Price controls

The simplest and most common[44] way to treat advance capacity challenge is to **include anticipatory investments in the TSO's regulatory asset base** (i.e. allowing them to be fully or partially refinanced

[43] In line with the Ministerial Council Decision on implementation of the 3rd Package, the Contracting Parties are legally obliged to implement these provisions until 1st January 2015.

[44] According to ACER's Recommendation on Incentives for PCI and on a Common Methodology for Risk Evaluation, a slight majority of EU MS include anticipatory investments in the RAB.

through regulatory remuneration). This mechanism is an obvious choice for infrastructure projects aimed primarily to increase security of supply (e.g. reverse flow projects) which are not financially viable, providing that significant positive externalities can be demonstrated.

Even if the infrastructure project is abandoned, the NRA may decide to allow for recovery of up to 100% of underlying prudently incurred costs, providing that the event occurred for reasons beyond the control of the project promoter[45]. While treating anticipatory investments as regular investments and socialising the associated risks between all network users introduces a compromise regarding the principle of cost-causality of network tariffs[46] and may introduce risks of excessive tariff increase (in gas sector this may adversely impact the number of new connections, creating a viscous circle underutilization- price increase- further decline of demand), this measure simultaneously effectively reduces the TSO's risk of anticipatory investments.

Further regulatory measures that may be considered complementary to including anticipatory investments in RAB while facilitating the cost-causality issue may be using **alternative depreciation methodologies** (e.g. annuity depreciation[47] or production unit depreciation[48]) shifting a portion of the depreciation towards the end of the asset life, when it is assumed that the network will no longer be underutilized. In this way, excessive prices at the start of the project are avoided. They may also provide reasonable assurances that cost recovery will be achieved over the life of the asset. A disadvantage of these methods is that they tend to be highly complex and are likely to put a considerable administrative burden on both the companies and the regulator (e.g. due to the need to recalculate depreciation, introduce corrections to account for differences between forecast and actual flows and actual capital expenditures in case of production depreciation etc.).

In case that including the anticipatory investment in RAB would considerably influence network tariffs within the period until full network capacity utilisation is reached, NRA may consider including in the price controls a **carry forward mechanism ("smoothing")** that will enable the TSOs to recover in later years (when the full capacity of connected production/demand is achieved) the revenue they forgo while their network utilisation is low. If these mechanisms are well-designed, they should be able to provide the TSO with reasonable assurances that they will get a return on their investments and to provide sustainable network tariffs. The regulatory costs of this mechanism depend on the pricing model used, but should not be as high as those of the alternative depreciation methodologies.

Furthermore, to protect consumers it must be ensured that the investment decision follows an assessment of the risks involved in providing advance capacity, taking into account the precise details of the investment and the level of uncertainty as to future capacity requirements.

In case that including anticipatory investments in RAB is for any reason not applicable, **introduction of semi-deep or deep connection charges** for under-utilized networks may be considered. Such connection charges may vary between shallow and deep, depending on NRA assessment on optimal proportion of cost

[45] Such incentive may be granted by FERC for transmission projects (ref. FERC, "Promoting transmission investment through pricing reform" (15 November 2012)).

[46] One may argue that including anticipatory investments in RAB results in unfair cost allocation between current and future users, especially in cases where shallow approach for connection charges is applied. The rationale for diverging from the cost-causality principle may be that although the network users bear the risk in the short term, they would profit in the long run thanks to lower overall costs.

[47] Methodology resulting in a constant payment of depreciation costs over the lifetime of the asset.

[48] Methodology resulting in constant depreciation charge per unit of output over the asset life. Since this method takes into account forecast flows, it may be especially useful in case of gas pipelines, because excessive pricing on the beginning of operation, when the design capacity is not reached yet, is avoided. Variants of this approach are seen in the countries in Northern Ireland as part of the concession agreement for Phoenix distribution and in Portugal with cost of capital smoothing for the first regulatory period.

coverage[49] between transmission use-of-system tariffs and connection charges. Full or partial compensation of connection costs addresses the liquidity risk of the network operator, and discourages request for over-dimensioned grid connections. On the other hand, the TSO's incentive to plan its expansions cost-effectively may be reduced. Furthermore, the decision of potential network users to connect to network may be adversely influenced by higher connection charges.

Network users' ex-ante financial commitment

Further means to facilitate the risk of sunk costs due to advance capacity challenge (while allocating it to those that are able to influence it) may be financial guarantees provided by a network user requiring additional network capacity in form of **deposits or capacity commitment agreements**. The party requesting additional network would either pay a deposit or sign an ex ante capacity commitment that would cover the costs of investments irrespectively if the capacity is used after realization or not. In case of the capacity being used by the relevant party, network tariff payments would be deducted from the deposit given.

3.2. The rules for recognition of efficiently incurred costs before commissioning of the project

Capital expenditure is required by the TSO or project company in the construction phase of a project, i.e. before the project is operational and starts creating cash flows. For major projects with high up-front costs, the construction phase may represent the most challenging phase in terms of financing. In order to reduce the liquidity risk, the NRA may to consider **allowing the developer to be remunerate (fully or partially) CWIP and other pre-commercial costs for the project during the construction phase,** while simultaneously introducing (ex-ante and/or ex-post) safeguards that the costs were incurred prudently**.** The measure would mean that there is no difference between the start-up phase and the operational phase from a risk point of view. Recognizing CWIP may also contribute to the stability of cash-flows and up-front regulatory certainty, resulting in lower capital costs and, where applicable, higher credit ratings.

3.3. Safeguards for recognition of efficiently incurred costs

One of challenges for any NRA is to develop its position regarding deviations between allowed and actual costs. These discrepancies may lead to substantial over- or under- recovery over the regulatory period; usually they are addressed by introducing a correction factor in the allowed revenue formula, allowing for variations between forecast (allowed) and actual costs of certain types.

Over- and under-recoveries may also be facilitated via regulatory accounts, where differences between allowed and actual revenues are annually recorded in the regulatory account and use-of-system charges accordingly adjusted afterwards.

[49] This optimal proportion depends on weighting the incentives to TSO to expand the network and incentives to network users to connect to the grid. Excessively high connection charges may reduce the incentive for the TSO to plan its expansion costs effectively or discourage network users to apply for connections.

3.4. Penalty-reward schemes

The rules providing additional return on the capital invested for the project

An approach to make investments in infrastructure more attractive with the introduction of **RoR uplifts ("equity return uplifts"** or **"equity return adders")** has already been implemented in various jurisdictions worldwide. The rationale for introducing the rate- of- return uplifts is to allow project promoters' additional return on equity for certain group of eligible projects (e.g. projects significantly contributing to market integration and security of supply) or on case-by-case bases. If the RoR uplifts would include CWIP, incentives would be provided in the year the capital expenditure takes place.

RoR uplifts may be considered as a proven tool to encourage infrastructure investment, addressing the regulatory and liquidity risks (long- term reliability of the regulatory regime, stability and predictability of cash-flows). While deciding on implementing this measure, the NRA shall analyse its effects in context of the whole regulatory framework in order to ensure that it is proportional – the investment should generate more benefits (making the network more efficient, reliable and cost-effective) in comparison to additional costs to the consumers[50]. In line with this, it has to be ensured that relevant risks and challenges are identified and minimized during the project development phase to the extent possible[51], that the effect of already existing risk-reducing incentives are accounted for while deciding on granting incentives or assessing their level, and that alternatives to the project have been considered. While designing RoR uplifts, NRAs should take into consideration the drawbacks inherent to of this mechanism[52]:

- incentive to the project promoter to overinvest;
- the possibility that an incentive is granted also for projects that would be implemented even without RoR uplift.

This may be addressed by network planning process (setting eligibility criteria) or by linking the RoR uplift with certain level of infrastructure utilization in case advance capacity challenge do not exists in the relevant market.

In jurisdictions where significant volatility of individual projects risk profiles in comparison with the risks accounted for in the default regulatory framework - i.e. average risk of the whole portfolio of investments - is observed, the NRA may find it appropriate to grant incentives on case-by-case basis and take into consideration introduction of **investment budgets**. Investment budgets are multi-annual cost approvals for eligible individual investment projects for a specified period[53]. If included in the investment budget, the project is added to the RAB and tariffs are adjusted accordingly,i.e. the project costs are added on top of the allowed revenues. If the investment budgets are applied within a jurisdiction where an incentive-based model of regulation is applied, the project may be excluded from efficiency requirements.

Negative incentives

"Negative incentives" is a common term for any mechanism obliging the TSO to use congestion revenues which are not re-invested (or a certain portion of them) for system expansion for tariff reduction.

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[50] Frontier Economics, "Improving incentives for investment in electricity transmission infrastructure" (2008).
[51] As an example, the liquidity risk arising from operating a capital intensive business (i.e. depreciation insufficient to prevent negative cash-flows) may be addressed by the project promoter by taking optimal and timely decisions related to capital structure.
[52] Frontier Economics, 2008.
[53] E-Bridge, Development of best practice recommendations on regulatory incentives promoting infrastructure investments (2011; study commissioned by the Energy Community Secretariat).

Starting from the responsibility of TSOs to meet reasonable demands and sort out capacity congestions by adding new investments as stipulated in Article 2 lit 4 Directive 2005/54/EC15 "negative" investment incentives are a possible regulatory tool. Where Article 6 para 6 lit c Regulation (EC) 1228/2003 (Article 16 para 6 Regulation (EC) 714/2009 – 3rd package) provides national regulators the possibility to decide on the use of congestion revenues, this allows national regulators to introduce a negative incentive of tariff reduction through congestion (e.g. auction) costs not used for sorting out long term congestion. Related to this Article 6 para 6 lit b Regulation (EC) 1228/2003 (Article 16 para 6 lit b Regulation (EC) 714/2009 – 3rd package) requires congestion revenues to be used for "network investments maintaining or increasing interconnection capacities". Article 6 para 6 lit c Regulation (EC) 1228/2003 further specifies that "Revenues […] shall be used […] as an income to be taken into account by regulatory authorities when approving the methodology for calculating network tariffs, and/or in assessing whether tariffs should be modified."[54] In addition, Article 16 para 6 Regulation (EC) 714/2009 of the EU 3rd energy package requests "If the revenues cannot be efficiently used for the purposes set out in points (a) and/or (b) of the first subparagraph[55], they may be used, [...] as income to be taken into account by the regulatory authorities when approving the methodology for calculating network tariffs and/or fixing network tariffs."[56]

4. Application of risk-related regulatory investment incentives to transmission PECI

4.1. General principles

NRAs may introduce regulatory investment incentives applicable for:

- a specific project (e.g. PECI). This requires a case-by-case decision of the NRA on granting incentives, taking into consideration the project-specific risk profile;
- a group of eligible projects including, but not exclusively, PECI (e.g. new investment, interconnection projects, projects introducing new technologies etc.), taking into consideration average additional risks applicable to the portfolio of eligible transmission infrastructure projects;.
- all investments of the TSO portfolio, taking into consideration average total risk (systematic and diversifiable) of the transmission activity. Practically, this would mean reviewing the currently applied price controls - what could be meaningful if a trend of under-investment is observed - with a view to enhance the investment climate.

By deciding on case-by-case basis, the required risk-reward correlation for PECI would be achieved in a most accurate way, while minimizing the risk for over- or under-compensation. On the other hand, these benefits have to be weighed against the complexity and high implementation and operation costs inherent for the case-by-case approach. Moreover, the Contracting Parties' NRAs would be faced with certain barriers in granting incentives for PECI on case-by-case basis:

54 For the gas market similar: Article 3 para 1 Regulation (EC) 1775/2003.
55 Lit (a) and (b) requiring that "Any revenues resulting from the allocation of interconnection capacities shall be used for the following purposes: (a) guaranteeing the actual availability of the allocated capacity; and/or (b) maintaining or increasing interconnection capacities through network investments, in particular in new interconnectors.
56 ECRB, "Cooperation of regulators on promoting new investments" (2010).

- limited access to mechanisms for regional/pan-European transmission infrastructure planning[57];
- uncertainties related to transmission PECI identification process[58];
- lack of a common legal basis for granting regulatory incentives to PECI projects[59] (they are not "visible" in national regulatory frameworks) and introducing complementary measures regarding permit granting and financing. If public interest for PECI is not established by law, any project specific regulatory incentive may be scrutinized as state aid. Furthermore, current legal framework does not set the optimal climate to explore synergies by setting a mix of incentive measures covering regulatory incentives, permit granting, CBCA and, where necessary, equity support at the same time.

In this context, it should be noted that the process of implementation of the TEN-E Regulation (EU) in the Energy Community regulatory framework was initialized by the Recommendation of the EnC Ministerial Council[60], envisaging, among others, adapting TEN-E Regulation for incorporation in the Energy Community acquis in its entirety at its meeting in (late) 2015. However, this should not discourage the Contracting Parties' NRA to introduce applicable regulatory incentives (e.g. those proposed in chapter III.3) targeted to a **group of eligible infrastructure projects** including, but not necessarily restricted to PECI (e.g. interconnectors, large scale internal lines, off-shore infrastructure, infrastructure involving new technologies), or even **all infrastructure projects**, even before the TEN-E Regulation is implemented in the Energy Community, as it was the case in several EU jurisdictions. The left side of figure 2 presents a proposed transitional model for introduction of regulatory incentives applicable for a portfolio of eligible projects, while the right side depicts the target mechanism, to be applied once the following prerequisites are fulfilled:

- Regulation (EU) 347/2013 implemented in the EnC regulatory framework, applicable both for the Contracting Parties and EU Member states (expected in late 2015);
- Contracting Parties implemented the 3rd Package, especially the stipulations on network planning (national TYNDP) and TSO unbundling;
- Project promoters are obliged to provide sufficient information to the NRA on financial viability of the project;
- National-specific barriers for implementation of PECI are identified[61] and underlying risks assessed and quantified;
- ENTSO-E and ENTSO-G CBA methodologies finalized, adopted within the EU framework and applied to projects candidate by Contracting Parties' promoters;
- Contracting Parties' TSO participate in ENTSOs network development planning process (Regional Investment Plans, EU-wide TYNDP); this is already the case in ENTSO-E.

[57] While majority of Contracting Parties electricity TSOs are, for historical and practical reasons, full Members of ENTSO-E, and their projects are included in the TYNDP, this is not the case with ENTSO-G. Therefore the results of the CBA and regional and European-wide positive externalities for natural gas infrastructure projects are not necessarily available to the Contracting Parties NRA as an input for granting the incentives.

[58] The identification of PECI has been performed by the EnC Strategy TF as a one-off activity, whereby the CBA applied differs from those drafted by the ENTSOs.

[59] Such legal basis establishing the concept of PCI, setting mechanism and criteria for their identification, obliging NRA to grant incentives to PCI promoters incurring high-risk etc. is provided to EU NRAs by Regulation (EU) 347/2013 (TEN-E Regulation).

[60] Recommendation of the Ministerial Council of the Energy Community No. 2014/01/MC-EnC of 23 September 2014 on Guidelines for Trans-European Energy Infrastructure.

[61] In line with Article 2 of the Recommendation of the Ministerial Council of the Energy Community No. 2014/01/MC-EnC of 23 September 2014 on Guidelines for Trans-European Energy Infrastructure, it is expected that "*By 31 March 2015, Each Contracting Party identifies in a report financial, administrative and regulatory barriers for implementation of the Projects of Energy Community Interest (in energy infrastructure categories) or Projects of Common Interest on the territory of their jurisdiction.*"

Also in the transitional phase (i.e. before implementation of the TEN-E Regulation), the Contracting Parties' NRAs should endeavour to take into consideration the general principles proposed by ACER to the extent possible[62] (see the text box below).

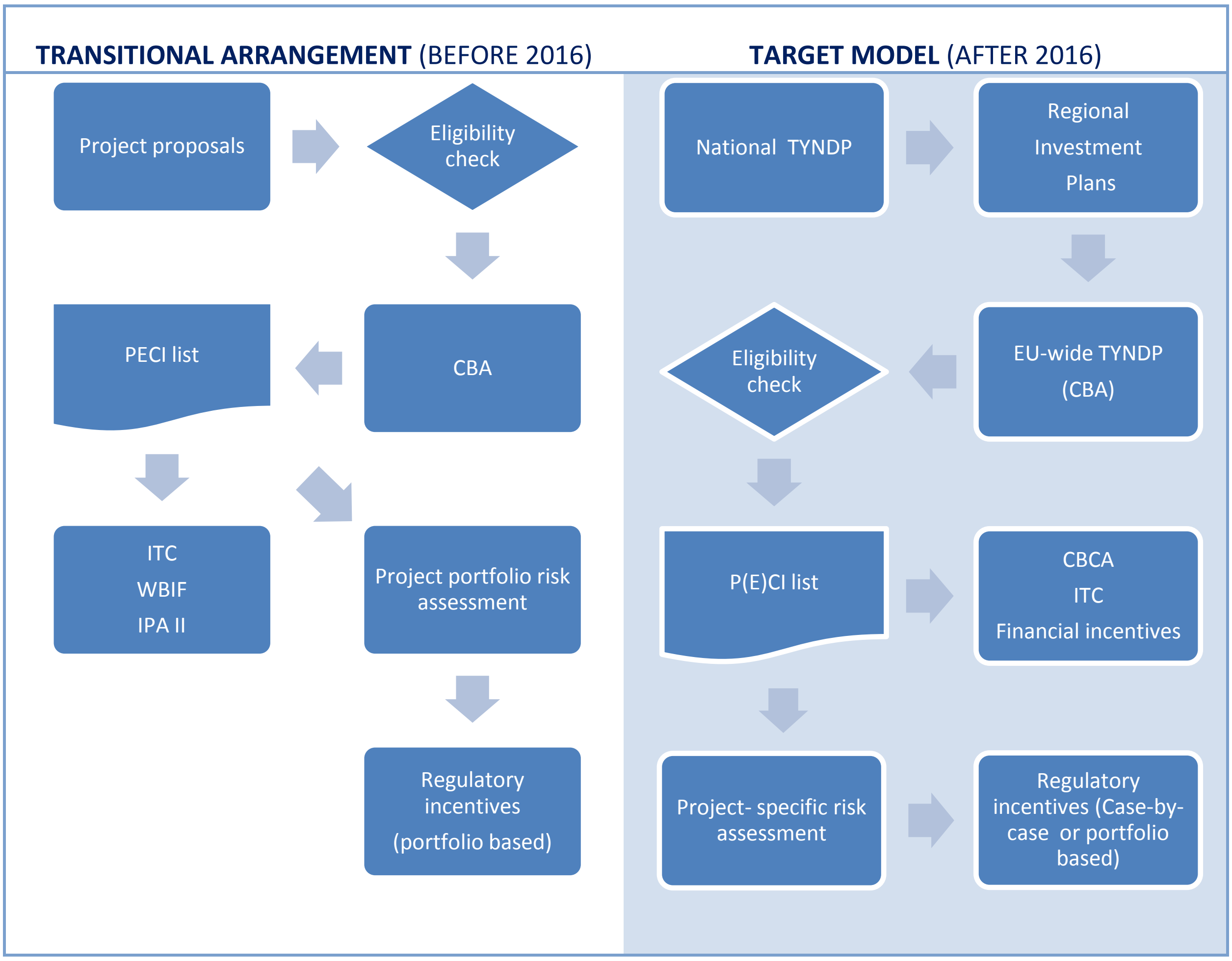

Figure 2: Mechanisms for introducing investment incentives

[62] Obviously, not all proposed general principles are applicable in jurisdictions where the TEN-E Regulation is not implemented.

GENERAL PRINCIPLES WHEN CONSIDERING INCENTIVES

- Additional incentives should be granted only to projects that are eligible according to Article 13 of Regulation (EU) No 347/2013.
- Based on national legislation and in accordance with Article 37(8) of Directive 2009/72/EC and Article 41(8) of Directive 2009/73/EC, NRAs may also grant incentives to non-PCI projects with particular risk profiles and, where appropriate, to all infrastructure projects (for example benefit-related incentives that are independent of the risk profile of a project).
- Incentives should not be granted to project promoters who do not disclose in a timely manner to NRAs the information necessary to apply the common risk methodology and do not, in particular, substantiate the existence of relevant, higher risks, along with the provision of reliable estimates of the net positive impact and the benefit/ cost ratio(s) of the project).
- Monetary compensations in the framework of Article 13 of Regulation (EU) No 347/2013 should not be granted for risks that are already reflected in the allowed cost of capital or where appropriate risk-mitigation measures are already in place (i.e. no "double counting").
- The incentives should be commensurate with the project's specific risk level as borne by the project promoters.
- NRAs should assess to what extent a project already benefits from subsidies, grants or from cross-border cost allocation contribution, for example based on Article 12 of Regulation (EU) No 347/2013. Subsidies, grants and cost allocation contributions should be considered when deciding on incentives to avoid over-compensation of project promoters. In the case of projects benefitting two or more MSs, the relevant NRAs should cooperate to guard against overcompensation.
- NRAs should assess the justification of the risk profile in view of the net positive impact provided by the project. The CBA methodology according to Article 11 of Regulation (EU) No 347/2013 should be used to quantify the net positive impact.
- The monetary value of the incentive should not result in project promoters receiving an overall compensation which exceeds the monetary value ofthe project's net benefits. This implies that project promoters need to monetise potential risks as well as the net positive impact of a project, and, as far as possible, NRAs should quantify in monetary terms the value of the (potential) incentives to the project promoter and the resulting overall compensation, and compare it to the positive benefit of the project as identified by the CBA. Furthermore, profit-sharing with network users should be considered: any incentive(s) should lead to a reasonable split of the welfare gain between project promoters and network users.

Source: ACER[63]

[63] Recommendation of the Agency for the Cooperation of Energy Regulators No 03/2014 of 27 June 2014 on incentives for Projects of Common Interest and on a common methodology for risk evaluation

4.2. Risk – related incentives

Chapter III.3 of the present recommendation paper proposes a menu of regulatory infrastructure investment incentives. The figure hereinafter provides an **indicative guidance** on incentives which may be used for specific types of risks.

In addition to this, the NRAs are advised to consider the ACER recommendation on particular risk mitigation measures (see the text-box below).

Risk of cost overruns	• Regulatory accounts • Correction factors
Risk of time overruns	• Regulatory accounts • Correction factors
Risk of stranded assets	• Including anticipatory investments in RAB • Alternative depreciation methods • Smoothing • Deep connection charges • Investment budgets
Risks related to recognition of efficiently incurred costs	• Regulatory accounts • Correction factors • The rules for anticipatory investment
Liquidity risk	• The rules for anticipatory investments • Recognition of efficiently incurred costs before commissioning the project • Regulatory accounts • RoR uplifts

Figure 3: Risk- related incentives

ACER RECOMMENDATIONS FOR PARTICULAR RISK MITIGATION MEASURES[64]

- Measures regarding the Risk of Cost-Overruns

The risk of cost-overruns does not apply to project promoters in cost-of-service and in incentive regulation systems as long as costs for CAPEX are incurred efficiently. In the cases of incentive regulation systems, the Agency also notes that caps may ensure that an appropriate risk-reward ratio is achieved. Specifically, price and revenue caps have an incentivising function where additional retums can be kept by the project promoter. This may increase the attractiveness of the PCI. The Agency recommends that, 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 due diligence could not reasonably be expected to reveal a priori. The adjustments should be set carefully (e.g. after evaluation of adequacy of costs) as network users should not automatically be burdened with the risk of inaccurate cost forecasts, especially concerning proven technology.

- Measures regarding the Risk of Time-Overruns

The risk of time-overruns does not apply 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. For other systems, the Agency recommends that NRAs should consider the recognition of efficient costs that may result from time overruns beyond the control of the project promoters.

- Measures regarding the Risk of Stranded Assets

Considering that PCIs are supposed to correspond to the most valuable projects in terms of net benefit for the European system, the Agency considers that PCI promoters are rarely exposed to the risk of stranded assets and recommends that the efficiently incurred CAPEX from PCIs should be approved and covered by tariffs, as appropriate under the national regulatory arrangements. In gas, in case a PCI has been decided according to a market test (minimum bookings from future users), the Agency recommends that the volume risk resulting from potential cancellation of some users' commitments is also addressed through TSOs' tariff structures, meaning that missing revenues are recovered from tariffs at other points of the system via a "regulatory account" recording the difference between the revenues which the TSO is entitled to obtain on the basis of the applied regulatory regime and the revenues actually obtained. For electricity, the Agency recommends that NRAs should consider the mitigation of the volume risk through a regulatory account.

- Measures regarding risks related to identification of efficiently incurred costs

Benchmarking and similar measures for the identification of efficiently incurred cost are important regulatory tools that may be applied to PCIs. However, the Agency recommends that NRAs should aim at ensuring that the specific features of a PCI are reflected in the design of the benchmarking scheme. This should also apply where anticipatory investments have been included into the RAB and the connected assets (e.g. power plants) unexpectedly are not built, for a reason beyond the control of the project promoters.

[64] Recommendation of the Agency for the Cooperation of Energy Regulators No 03/2014 of 27 June 2014 on incentives for Projects of Common Interest and on a common methodology for risk evaluation.

- Measures regarding Liquidity Risk

In order to mitigate liquidity risks as far as possible from a regulatory perspective, the Agency recommends that NRAs 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, the Agency recommends that NRAs consider approving them and their inclusion in the Regulatory Asset Base when the expenditure is incurred.

Annex I - Regulatory frameworks, WACC and its components

Table 1: Regulatory frameworks, WACC and its components- electricity transmission

	Regulatory framework	Regulatory period	WACC (real, pre-tax)	Gearing[65]	Return on equity	Return on debt	Risk free rate	Beta	Market risk premium
		(years)	%	%	%	%	%		%
Albania	Price cap	3	5.47	60	8.515[66]	3.44[67]	-	-	-
Bosnia and Herzegovina	Rate- of-return	1	0,67% on capital value	-	-	-	-	-	-
Croatia	Rate- of-return	1	5.67	21	6.11	5.02	-	-	-
FYR of Macedonia	Revenue cap	5	5.65	60.69	8.53	2.33	4.68[68]	1	3.85
Kosovo*	Revenue cap	3	5.07	40	6.1	4[69]	4[70]	1[71]	0.6
Moldova	Revenue cap	3	8.95	50	8.705	8	1.95[72]	Not used	Not used
Montenegro	Revenue cap	3	7.24[73]	50	10.9	6.81[74]	1.93[75]	0.68[76]	6
Serbia[77]	Rate- of-return	1	7.0	60	9	5.0	4.8	0.83	6.2
Ukraine	Rate- of-return	1	-	-	-	-	-	-	-

Source: ECRB, "Status Review of Main Criteria for Allowed Revenue Determination for transmission, distribution and regulated supply of electricity and gas" (2013)

[65] debt/(debt + equity)
[66] Equal to treasury bond rate.
[67] Return on debt is calculated as the sum of interest payments on long term debt during the year, divided by the total principal on long term debt (the total amount borrowed) at the beginning of the year). The figure for the rate of debt reported in the table is the average for the three years of the regulatory period.
[68] Return on government bonds.
[69] Weighted average interest rate of existing long- term loans of the TSO/MO.
[70] Determined by the government.
[71] As similar utilities internationally.
[72] Treasury bonds risk- free rates of USA with maturity more than 10 years, according to statistics published on Bloomberg.
[73] WACC is different for every year in the regulatory period (2012-2015). This is the figure for the third regulatory period, i.e. from 1st August 2014 to 31st July 2015. For the past years it was 6.80% and 7.02% respectively.
[74] Set as the sum of risk-free rate and country risk- premium. The country risk premium is equal to the premium for the risk of non-payment of a country, multiplied by the volatility coefficient of the capital markets in developing countries.
[75] If parameters not available in Montenegro, the rate shall be equal to the average annual rate of return to German Government bonds for December of the previous year with maturity of 10 years.
[76] Calculated based on international benchmarks.
[77] All figures for 2013.

Table 2: Regulatory frameworks, WACC and its components- natural gas transmission

	Regulat. framework	Regulat. period	WACC (real, pre-tax)	Gearing[78]	Return on equity	Return on debt	Risk free rate	Beta	Market risk premium
		(years)	%	%	%	%	%		%
Albania	-	-							
Bosnia and Herzegovina-RS	Rate- of-return	1	1,80	-	-	-	-	-	-
Croatia	Revenue cap	3 (5)[79]	7,32 (nominal,pre-tax)	50	8,63	3,85	5,5[80]	0.54[81]	5,80[82]
FYR of Macedonia	Revenue cap		9,39	1,25	8,53	2.33	4.68[83]	1	8.53
Kosovo*	-	-	-	-	-	-	-	-	-
Georgia	Rate- of-return	1	8	-	-	-	-	-	-
Moldova	Revenue cap		12,23	35	12,23	9,13	1,8[84]	0.70[85]	5,26
Montenegro	-	-	-	-	-	-	-	-	-
Serbia[86]	Rate- of-return	1	7,50	60	10	5,10	4.8[87]	0.83[88]	6.2[89]
Ukraine	Rate- of-return	1	-	-	-	-	-	-	-

Source: ECRB, "Status Review of Main Criteria for Allowed Revenue Determination for transmission, distribution and regulated supply of electricity and gas" (2013)

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78 debt/(debt + equity)

79 For the first regulatory period (2014-2016) a 3-years revenue cap is applied, after which a 5-years revenue cap will be used.

80 The risk free rate is determined on the basis of the nominal interest rate of latest domestic or international ten year bond issued by the Republic of Croatia.

81 The beta coefficient is determined on the basis of a comparative analysis of the gas system operators' beta coefficients applied in the regulatory mechanisms of European countries.

82 Market return is calculated as the sum of the risk-free rate and the market risk premium, which is determined based on the expected rate of return on the diversified market portfolio in the Republic of Croatia.

83 Return on Government bonds.

84 Based on the treasury bonds risk free rates of USA with maturity of more than 10 years according to statistics published on Bloomberg.

85 Based on data published in the statistical summary of *DAMODARAN*, in the part "Betas of industry", natural gas enterprises in the developing countries (http://pages.stern.nyu.edu/~ADAMODAR/New_Home_Page/datafile/Betas.html).

86 All figures represent the average of minimum and maximum values used for calculation.

87 Nominal rate of long term Governmental bonds decreased by percentage of inflation.

88 International benchmark, as energy utilities in the SAD.

89 Calculated as the sum of risk-free rate in other countries, market premium in other countries and country credit rating of Serbia minus country credit rating in other countries.

Annex II - ACER Recommendation on a common methodology for risk identification and risk assessment

Step 1: Availability of information on project risks

The Agency considers that, since project promoters are best informed about the project's features and aspects, risk evaluation shall be primarily carried out by them. Project promoters should 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.

The results of the cost-benefit analysis (CBA) (for example, sensitivity analyses) can be used in risk assessments. The Agency notes that the CBA and the risk analysis should use consistent assumptions and data sets. In this sense, the risk assessment should rely on the same data and on the same assumptions used to evaluate the financial sustainability and the socio-economic net benefit in the context of the PCI selection process, in accordance with Annex III.2(1) of Regulation (EU) No 347/2013, and, when applicable, in the context of cross-border cost allocation, in accordance with Article 12(3) of Regulation (EU) No 347/2013.

Step 2: Identification of the nature of the risk from a regulatory point ofview

The Agency recommends the evaluation of the risk of the project:

i) by each concerned NRA, in relations to the respective national regulatory framework and,

ii) jointly by all the concerned NRAs, with regards to risks linked to any necessary cross-border coordination

The Agency considers that all project risks can, in general, be subsumed under five categories of risks from the perspective of project promoters. The Agency recommends using the following categorisation for the assessment of risks:

a) The risk of cost overruns

The risk that during development, construction, operation or maintenance of a project, the actual costs turns out to be higher than the expected project costs approved ex-ante by NRAs. For example, higher costs (due to more uncertain cost estimates compared to other investments) can result from:

- new transmission technologies, both onshore and offshore, and development risks;

- innovative transmission technologies for electricity allowing for large-scale integration of renewable energy, of distributed energy resources or of demand response jn interconnected networks; and
- gas transmission infrastructure offering advanced capacity or additional flexibility to the market to allow for short-term trading or back-up supply in case of supply disruptions.

b) The risk of time overruns

The risk that development and construction of a project takes longer than anticipated by the project promoters and approved by the NRA. This risk can translate into non-timely compensated costs for project promoters.

c) The risk of stranded assets

The risk that the demand for the services of the PCI will unexpectedly decline (or will not rise to projected levels), due to reasons which are not under the control of the project promoters. This includes volume risk.

d) Risks related to the identification of efficiently incurred costs

The risk that costs are not considered as being efficiently incurred based on benchmarking or other measures used by NRAs.

e) Liquidity risk

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.

Step 3: Risk-mitigation measures by the project promoters

In all cases, and regardless of the nature of the risk, the Agency recommends that NRAs 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.

Step 4: Assessment of systematic risk and definition of cost of capital

The Agency recommends NRAs to 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 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).

Step 5: Risk-mitigation measures already applied by NRAs

The Agency recommends NRAs to assess if there is a regulatory instrument that is already in place that mitigates the risk fully or partially.

Step 6: Risk quantification

The Agency recommends that NRAs, as far as possible, 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 occurence, 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.

Step 7: Comparable project

The Agency recommends NRAs to 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 altemative in view of the net positive impact provided by the project. Among other things, higher risks may result from technical specificities (in terms of technology, capacity or design of the project) or from the cross-border nature of a project.

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 PCI status (and the streamlined permitting procedure introduced by Regulation (EU) No 347/2013) increases the social acceptance of the project and (consequently) the project planning and permitting procedures are facilitated.

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 countries 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 MSs, 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.

Source: ACER[90]

90 Recommendation of the Agency for the Cooperation of Energy Regulators No 03/2014 of 27 June 2014 on incentives for Projects of Common Interest and on a common methodology for risk evaluation

Annex III - Questionnaire on regulatory incentives- summary of results

Table 3: Questionnaire on regulatory incentives- summary of results

TRANSMISSION $_{G,E}$, STORAGE, LNG			
1 - FINANCIAL INCENTIVES			
Incentive	**✓Existing**	**👍 Not existing but supported**	**👎 Not existing and not supported**
Higher RoR	1. ROM +1,4% [$G_{T,St}$] 2. AT	Croatia [$G_{T,\ St,\ LNG}$]	1. Moldova [G_T, E_T] - arg. existing RoR level sufficiently „incentivizing“ 2. Serbia [$G_{T,\ St}$, E_T] / model not clear [G_{St}]
„Negative“ incentive		1. Moldova [E_T] – Reg 1228 adoption pending 2. Croatia [$G_{T,\ St,\ LNG}$] – model not clear	1. Moldova [G_T] – arg. no revenues 2. Serbia [E_T] / model not clear [G_{St}]
„Stimulative“ depreciation		1. Croatia [$G_{T,\ St,\ LNG}$] – planned 2. ~Serbia [G_{St}] - model not clear	1. FYR of Macedonia – arg. tariff increase 2. Moldova [G_T, E_T] 3. Serbia [G_T, E_T]
„Non-domestic“ investments – Recognition in RAB		FYR of Macedonia	1. Croatia [$G_{T,\ St,\ LNG}$] – model not clear 2. Moldova [G, E] – no legal powers 3. Serbia [$G_{T,\ St,\ LNG}$, E_T]
„Non-domestic“ investments – NRA CB coordination on capacity allocation / tariff setting		1. FYR of Macedonia 2. ~Serbia [G_T, E_T]	1. Croatia [$G_{T,\ St,\ LNG}$] – model not clear 2. Moldova [G, E] – no legal powers 3. Serbia [$G_{St,\ LNG}$] – model not clear

2- INCREASING PREDICTABILITY			
Incentive	✓**Existing**	**Not existing but supported**	**Not existing and not supported**
Longer regulatory period		Serbia – may be considered in general	1. Croatia [$G_{T, St, LNG}$] 2. FYR of Macedonia – arg. tariff increase 3. Moldova – model not clear 4. Serbia – model not clear
Capacity expansion agreement	1. Croatia [G_T] 2. FYR of Macedonia [G_T, E_T]		1. Croatia [G_{St}] – model not clear 2. Serbia – model not clear
Investment costs covered in the RAB, if part of national investment plan approved by NRA	1. Croatia [$G_{T, St}$] 2. FYR of Macedonia [G_T, E_T] 3. Moldova [G_T, E_T] – TSO investments		Serbia – model not clear
Recognition of stranded costs	FYR of Macedonia [G_T, E_T]	Croatia [G] – model not clear	Moldova – model not clear
3 - OTHER			
Incentive	✓**Existing**	**Not existing but supported**	**Not existing and not supported**
Accelerated permit granting		FYR of Macedonia – task of government	1. Croatia [G] – no legal powers 2. Moldova [G, E] – no legal powers 3. Serbia [G, E] – no legal powers
Coordinated licensing (NRAs)		1. Croatia 2. FYR of Macedonia	1. Moldova [G, E] – no legal powers 2. Serbia [G, E] – ref. ECRB licensing paper
CB coordinated NRA rules	FYR of Macedonia [E_T]	FYR of Macedonia [G_T]	1. Croatia - model not clear 2. Moldova [G, E] – no legal powers 3. Serbia [G, E] – model not clear
Indicators + reference values for		1. Croatia 2. FYR of Macedonia	Moldova [G, E] – no legal powers

comparison of unit investment costs for comparable projects (develop and publish in cooperation with other NRAs)		3. Serbia	
Existing RoR level sufficiently „incentivizing“	1. FYR of Macedonia [2012: 6,91% E_T, 9,39% G_T] 2. Moldova [G_T, E_T]		
Proposals	- Croatia: regulatory account		
GENERATION			
Incentive	✓**Existing**	**Not existing but supported**	**Not existing and not supported**
Accelerated permit granting	ROM	1. FYR of Macedonia – task of government 2. Serbia – task of government	Moldova [G, E] – no legal powers