Study on regulatory incentives for investments in electricity and gas infrastructure projects

Final Report
Study on regulatory incentives for investments in electricity and gas infrastructure projects – Final Report
# Study on regulatory incentives for investments in electricity and gas infrastructure projects
## Final Report

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EXECUTIVE SUMMARY

Introduction

Article 13 of the TEN-E regulation sets out that if a project promoter incurs higher risks for the development, construction, operation or maintenance of a project of common interest (PCI) than comparable investments, and the project’s net positive impact is confirmed by cost-benefit analysis (CBA), then appropriate incentives shall be granted.

PCIs can be generally described as major energy infrastructure projects that contribute to the timely development and interoperability of European energy networks. As a consequence, PCIs are typically cross-border projects, meaning that they involve investments in multiple countries or their benefits will accrue to multiple countries. (Part of) PCIs’ benefits will regularly consist of increased security of supply or increased competition in supply, and may therefore be difficult to internalize. Finally, PCIs may be technologically challenging, for instance electricity network investments to connect off-shore wind farms.

Given this background, the EC has asked AF-Mercados EMI and REF-E to look into possible risks and existing incentive and regulatory frameworks. We have investigated how specific features of PCIs impact the risks faced by project promoters, and may therefore justify special regulatory treatments. This risk dimension is crucial as it may significantly impact the financing cost of the project and thereby the project’s viability. We have also investigated potential regulatory incentives or measures to either reduce the project promoter’s risk or efficiently reward the project promoter for bearing the risk. In particular, we have been asked by the EC to conduct the following four tasks:

1. Take an inventory of possible risks;
2. Identify a common methodology or criteria to establish whether a PCI faces higher risks than comparable investments;
3. Identify best-practices for regulatory incentives; and

Below we summarize our findings and highlight the policy implications of our analysis.

Concept of risk

A PCI is subject to various project risks. Examples of project risks are permitting delays during the development phase of the investment, cost and time overruns during the construction phase, and cost overruns and technological failure during the operational phase of the investment. Depending on the exact moment in the investment’s lifetime, project risks could lead to a PCI being delayed (or even cancelled), becoming more costly than anticipated, or being frequently disrupted (or even early decommissioned). Project risks may therefore cause PCIs not (fully) realizing their expected net benefits, thereby causing concerns to the EC. The EC is particularly concerned about the (timely) delivery of PCIs.

For the purpose of developing policy implications regarding PCIs, we identify two broad categories of project risks:

- Risks related to the (technical) characteristics of PCIs, so-called project-specific risks; and
- Risks related to the institutional setting of PCIs, so-called systemic risks.

Project-specific risks are for example related to the technical lifetime of the infrastructure’s components, the time-out-of-use during the investment’s lifetime, and the uncertainty during the construction phase about the investment going to be
Systemic risks are for example related to adverse legislation, adverse regulatory decisions, and failure in coordinating major investments resulting in excess capacity and stranded assets.

The main difference between these two risk categories is that the former is to a large extent beyond the control of the public institutions, whereas the latter is generally under their control. We realize that this distinction is somewhat arbitrary. For instance, an NRA lacking credibility may not be able to effectively control the risk of adverse regulatory decisions overnight as it takes time to build up a track record. Nevertheless we consider this distinction to be a useful analytical device. To the extent that in practice some systemic risks are not controllable by the public authorities, they should be treated as project-specific risks for the purpose of designing effective regulatory incentives or measures.

A project promoter’s risk can be defined as uncertainty with respect to the project’s return on investment, the project’s revenue stream and the liquidity of the investment. In other words, the project promoter’s risk consists of uncertainty regarding the timing and amounts of the costs and revenues resulting from the project. In general, risks are examined in this study with regard to their potential to influence a project promoter not to take a positive final investment decision and therefore not to proceed with developing or constructing a PCI.

Typically, not all project risks are also project promoter’s risks. For instance, deciding to cancel a project due to (expected) financing difficulties at an early stage, meaning before the project promoter has incurred any significant costs in terms of time and other resources or has made any significant commitments, is a project risk. Such a decision would however not constitute a real risk for the project promoter. Furthermore, in a regulated environment some project risks will typically be carried by the users of the infrastructure investment instead of the project promoter. Consider for instance volume risk, which is related to the actual use of assets and determines the revenues of the project promoter. In case the regulatory framework assigns volume risk to the project promoter, it faces the uncertainty of its revenues being insufficient to cover the costs or its revenues exceeding the costs. In case the users carry the volume risk, under- or over-recovery of costs by the project promoter in a specific year will lead to tariff increases or decreases in a subsequent year (or subsequent years) to compensate for any under- or over-recovery of costs in that specific year.

Regulatory risks are project risks which are can be influenced by the NRA’s regulatory framework. Regulatory risks mostly relate to uncertainties for project promoters with regard to cost recovery. Regulation is, however, not only a source of risk for project promoters, but also offers a way to deal with (part of) the risks resulting from other risk factors. In particular, regulation can distribute risks between the project promoter and the users of the infrastructure, as shown by the above mentioned example of volume risk. We have been asked to give specific attention to regulatory risks, as they are typically factors which may cause great concern, and which NRAs can generally affect.

Inventory of possible risks

We have identified seven categories of possible risk factors to which a PCI may be exposed:

- Policy and legal;
- Planning and permitting;
- Regulation;
- Finance and capital markets;
- Energy markets;
- Technology; and
- Geographic distribution of costs and benefits.
NRAs and project promoters hold distinct views on the significance of regulatory risks faced by PCIs. NRAs consider that PCIs face relatively low levels of regulatory risk; this contrasts to TSOs, which view regulatory risks as being relatively more severe. The analysis has also shown, however, that within the respective NRA and TSO groups, there does not seem to be a single and unanimously held view on regulatory risk significance. The feedback that we have received from stakeholders showed that the most significant regulatory risks seem to be:

- Cross-border coordination issues;
- Future adverse regulatory decisions; and
- Financing issues.

In the PCI context, where projects are typically cross-border in nature, differences between national regulatory frameworks result in further uncertainty in the way projects are treated from a regulatory perspective. Future adverse regulatory decisions refer to potential future changes in the regulation, including direct intervention in cost recovery mechanisms (RAB, WACC etc.). Financing issues concern for instance failure in ensuring adequate investment capital, difficulties of project promoters in maintaining equilibrium (liquidity) on their balance sheets, or unfavourable conditions for refinancing of projects during the project’s lifetime. As mentioned above, not all project risks are also risks to the project promoter.

It should be noted that cross-border coordination issues are not only considered significant by TSOs and other project promoters, but also by NRAs.

**Methodology and criteria to assess investment risks**

A direct valuation of risk as a basis for incentives is no easy task, nor can it be the outcome of consolidated, science-based methodologies. It is rather an exercise that is influenced by the perception of risks by project promoters as well as their production factor providers, notably financial institutions. Therefore, any general definition of risk and any approach to its valuation as a basis for the provision of an enhanced regulatory treatment should be addressed with great care, as it can only play a limited role in incentive provision.

Risk evaluation can generally be better performed by project promoters and financiers, who have the best resources and expertise to implement it. However, if they know that risk evaluation can lead to incentives, there is clear scope for strategic behaviour. As for the choice of an approach to risk evaluation, the limited availability of objective criteria suggests that the transparency of evaluation procedures could matter more than the technical methodology itself.

When considering an approach to risk evaluation it is certainly wise always to verify if objective parameters do exist: if that is the case, these can be the basis of “output based regulation”, where part of the benefits arising from projects is left to their promoters: in this way risk evaluation and incentive definition are merged. In a few cases, it is also possible to attach parts of the incentives to output indicators rather than to risk. Examples are the achievement of security of supply parameters, the reduction of price differences between adjacent markets, and the increased connection of renewable or other preferred sources of electricity and gas. Yet in other cases, no such approach may be feasible, because special risks of some projects are not necessarily linked to any quantified benefit. In these cases, risk assessment is necessary. As said, whilst some methodologies do exist for such an evaluation, their rather subjective nature entails that their use should be characterised by the greatest care.

**Best-practices for regulatory incentives**

We have considered regulatory incentives focusing on the theoretical potential of each incentive, as well as considering present-day examples of the use of incentives in certain
EU Member States, and highlighting the views of project promoters and NRAs relating to the potential application of specific incentives. A regulatory incentive often has a unique potential applicability in terms of the specific risks that it can address. Additionally, different regulatory incentives can potentially be used to treat the same risk. This means that NRAs have flexibility in choosing how to address specific identified risks through using a particular regulatory incentive, if indeed they opt to use incentives. Consequently, a variety of distinct approaches are currently in operation in the various Member States which have opted to use regulatory incentives. Specifically, individual countries have tailored the design of regulatory incentives to suit their specific conditions and requirements.

Stakeholders have expressed their view that certain regulatory incentives have significant potential to help offset risks associated with PCI investments. However, as said, there is no commonly-agreed view regarding the level of necessity of regulatory incentives. This variation in the views of stakeholders regarding the optimal use of regulatory incentives fits well with suggestions to apply specific incentives – where they are required – on a case-by-case investment basis. Despite the variation in different stakeholders’ views on the need to apply regulatory incentives to address PCI risks, there is general agreement that the two most necessary regulatory incentives or measures are:

- Stability provisions; and
- Measures to mitigate liquidity risk (although liquidity risk is not necessarily a problem in all Member States).

Below we describe these two regulatory incentives or measures in more detail.

**Stability provisions**

Regulatory arrangements are often required to be re-shaped due to changes in policy frameworks and legislation, over which NRAs have no control and are duty-bound to follow. However, various tools are employed by NRAs to provide regulated companies with some guarantee of regulatory stability, including:

- Using fixed regulatory terms, where the regulator guarantees not to adjust certain key factors during a specific period of time, or even a total ban on retroactive decisions including adverse recalculation of the RAB or lowering the allowed return on investment;
- Regulators may also strive to ensure that they give notice to companies if and when they are considering options for changing regulation;
- Regulators can also consult with regulated companies to get their inputs on how changes could be designed and implemented in a way that reduces any costs of adjustments and may reshape desired outcomes to fit better with companies’ capabilities;
- Regulators can also implement any changes in stages to ensure smooth transitions and a framework which is as stable as possible, or apply longer regulatory periods;
- Regulators can give companies some flexibility in complying with any regulatory adjustments and the means with which they achieve compliances; and
- Regulators may provide a large amount of information, advice and support to companies regarding regulatory changes and potential future developments. This results in companies having a solid understanding of what and why the regulator is aiming at achieving through any regulatory developments.

**Measures to mitigate liquidity risk**

Measures to mitigate the liquidity risk include the following:
• The early recognition of costs;
• The inclusion of anticipatory investments;
• TSO revenues based on scheduled rather than actual capacity or flow measures (possibly subject to correction through regulatory accounts);
• Monitoring the investment grading of the involved TSOs; and
• Using a more favourable depreciation regime.

Construction work in progress (CWIP) is the term used to describe the money that has been spent, at a given point in time, on an infrastructure asset that, at that time, had still not been commissioned. Due to the very large scale of infrastructure investments (and significant construction periods), some NRAs allow specific arrangements for CWIP. Regulatory arrangements for early recognition of costs could take a few forms, including:

• The regulator may allow the capitalisation of either debt or equity costs (or both) incurred by the regulated company during the construction period;
• A regulator might allow the inclusion of the allowed return on debt or equity (or both), but does not include the depreciation in the allowed revenue during the infrastructure construction period; or
• A regulator could also decide to partially include CWIP within the regulatory asset base, which could be a favourable option for projects with a relatively short construction period.

NRAs may establish - and communicate to project promoters - well-reasoned rules relating to anticipatory investments in infrastructure which will be needed in order to prevent inadequate and untimely infrastructure developments. Well-considered anticipatory investments also help to keep various future infrastructure development options open and feasible. However, it is unaffordable and unrealistic to try to keep all options on the table for an indefinite period of time. Hence, the use of clear and well-considered rules for anticipatory investments can help to ensure that companies understand which types of investments to undertake.

Given that depreciation can account for a significant proportion of a regulated company’s total costs, such companies will be more motivated to make investments in infrastructure when they enjoy greater certainty that their depreciation costs will be recovered (and conversely, will be less motivated to make investments when there is less certainty that their depreciation costs would be recovered). A key aspect of ensuring that companies are incentivised to make investments is to ensure that the pattern of recovery and the period over which the invested capital is returned to the company are favourable.

**Recommendations for guidelines**

To implement article 13 of the TEN-E regulation we propose both a procedure and guidance on the incentive design.

**Procedure**

We propose a procedure to be open for all PCIs, but actually aimed at – and likely limited to – the most difficult cases. Such a procedure should preferably be based on moral suasion rather than binding rules. Further, it may be too early for binding rules, as a voluntary approach should be tried first. The procedure would envisage a streamlined decision process, centred on a Project Conference (PC), which is meant to:

• Streamline cooperation and procedures (to deal in particular with any regulatory cross-border issues);
• Promote public commitment on the application of regulatory incentives; and
• Increase transparency and stakeholder participation.
**The PC should not be a decision-making body, or an instrument to bypass already existing institutions, such as ACER. It should not create another layer of bureaucracy and should be fast and simple, avoiding further delays to the investment being commissioned.** The process would also include a non-binding judgment by external experts, appointed by regulators, to help the realisation of a fast decision in case of disputes.

**Incentive design**

First, we focus on minimizing systemic risks, meaning risks related to the institutional setting of PCIs. A well-known example of a regulatory incentive or measure that reduces systemic risks is the use of the Ten-Year Network Development Plan (TYNDP) – and underlying national and regional investment plans – since 2010 to achieve a timely and well-planned development of energy network infrastructure in the EU. By identifying gaps in infrastructure from a European perspective and informing stakeholders on major investment projects, the TYNDP contributes to an EU-wide consistent and transparent investment planning process. The TYNDP thereby reduces the risk that infrastructure investments turn out to be redundant after they have been commissioned.

Reducing systemic risks is not limited to a regulatory context. Dealing with intergovernmental cooperation in the energy sector, the 1994 Energy Charter Treaty is an example of a policy measure that reduces systematic risks. The Treaty provides a multilateral legal framework aiming to strengthen the rule of law on energy issues, thereby minimizing the risks associated with energy-related investments and trade. The Treaty focuses on the protection and promotion of foreign energy investments; free trade in energy materials, products and energy-related equipment; freedom of energy transit through pipelines and grids; improving energy efficiency; and mechanisms for the resolution of state-to-state or investor-to-state disputes. Policy risk may however still be perceived as high in several Member States. Consider for instance the 2013 reform of renewable energy remuneration system in Spain, which led the Spanish energy sector to take severe losses on previous investments in terms of missed subsidies and guaranteed revenues.

As mentioned above, we do not recommend the harmonisation of one or more regulatory instruments across the entire EU. Yet, we found that there is general agreement, across all stakeholder groups, that minimizing systemic risk by providing stability provisions is one of the two most necessary regulatory incentives or measures. Consequently, the guidelines should recommend that, when deciding on appropriate incentives for a PCI with a higher risk profile than comparable projects, NRAs should focus on stability provisions.

PCIs’ benefits will partly consist of increased security of supply or increased competition in supply and will therefore be based on achieving excess transportation capacity. If merchant investments are supposed to remain viable under these circumstances, then regulatory incentives or measures need to be put in place to ensure that the excess capacity does not reduce the value of the non-excess capacity. Value of Lost Load (VoLL) pricing of strategic reserves in electricity generation is an example of such a measure.

Second, we deal with project-specific risks and their optimal allocation through the applied regulation. Regulatory theory suggests that risks should be carried by project promoters if and only if it is necessary to incentivise them to be efficient. Reason is that risk taking by project promoters has to be compensated and therefore comes at a price to the users of the infrastructure. Regulatory theory also suggests that cost-plus regulation provides strong incentives for developing new infrastructure; under cost-plus regulation the rate of return on the asset base is guaranteed and the risk faced by the regulated firm is therefore significantly reduced. Price-cap regulation may weaken the incentive to invest in new infrastructure due to regulatory opportunism when regulatory periods are shorter than the assets’ lifetimes.
Based on these considerations PCIs should generally be regulated in a way that leaves project promoters with relatively little risks. Such an approach will reduce financing costs and encourage investments. Reducing project promoters’ risk could for instance be realised by assigning volume risk to users, regulating innovative projects on a cost-plus basis, or committing to not taking adverse regulatory decisions regarding an investment’s efficiency.

The resulting loss of incentives for project promoters to deliver PCIs efficiently and in time can under such circumstances be pursued in alternative ways: organising tenders to procure the investment’s technology and the party to construct the infrastructure, close monitoring of progress by the NRA, and potentially using incentive schemes on specific targets (for instance the commissioning date).

We have found that there is general agreement, across all stakeholder groups, that the other most necessary regulatory incentive – next to stability provisions – is measures to mitigate liquidity risk. Measures to mitigate liquidity risk are another example of regulating PCIs in such a way that little risk is left with the project promoters. Consequently, the guidelines should recommend that, when deciding on appropriate incentives for a PCI with a higher risk profile than comparable projects, NRAs should particularly focus initially on measures to mitigate liquidity risk.

Only if mitigating incentives (like stability provisions and measures to mitigate liquidity risk) are not regarded as sufficient should NRAs apply rewarding incentives like rate of return premiums.
Chapter 1 – Introduction
1 INTRODUCTION

Projects of common interest

In October 2013, the European Commission (the EC) adopted a list of 248 key energy infrastructure projects. Labelled as "projects of common interest" (PCIs), they will benefit from streamlined permit granting procedures and, in some cases, improved regulatory treatment and EU financial assistance, to facilitate their implementation.

PCIs can be generally described as major energy infrastructure projects that contribute to the timely development and interoperability of European energy networks. As a consequence, PCIs are typically cross-border projects, meaning that they involve investments in multiple countries or their benefits will accrue to multiple countries. (Part of) PCIs' benefits will regularly consist of increased security of supply or increased competition in supply, and may therefore be difficult to internalize. Finally, PCIs may be technologically challenging, for instance electricity network investments to connect offshore wind farms.

Particularly on regulatory treatment, article 13 of the TEN-E regulation1 sets out that if a project promoter incurs higher risks for the development, construction, operation or maintenance of a PCI than comparable investments, and the project’s net positive impact is confirmed by cost-benefit analysis (CBA), appropriate incentives shall be granted. It also asks the Agency for the Cooperation of Energy Regulators (ACER) to provide best-practices and recommendations for adequate measures, and provides the EC with the possibility to issue guidelines later on, if necessary.

Study on regulatory incentives for investments in electricity and gas infrastructure projects

To support ACER and the EC with the analytical tasks, the EC has asked AF-Mercados EMI and REF-E to look into possible risks and existing incentive and regulatory frameworks in Europe and elsewhere. We have investigated how specific features of PCIs impact the risks faced by project promoters, and may therefore justify special regulatory treatments. This risk dimension is crucial as it may significantly impact the financing cost of the project and thereby the project’s viability. We have also investigated potential regulatory incentives or measures to either reduce the project promoter’s risk or efficiently reward the project promoter for bearing the risk.

AF-Mercados EMI and REF-E have in particular been asked to:

1. Take inventory of possible risks.
2. Identify a common methodology or criteria to establish whether a PCI faces higher risks than comparable investments.
3. Identify best-practices for regulatory incentives.

Purpose and structure of the Final Report

The Final Report is an upgraded version of the Interim Report that has previously been submitted to the Steering Board. It covers all tasks of the assignment and includes the outcomes of all research, interviews, as well as the comments received during and after the project workshops.

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The report is divided into four sections. Section 2 describes cross-border infrastructure investments and their risks; Section 3 considers a common methodology and criteria to evaluate investments and their risks; Section 4 deals with the use of regulatory incentives; and Section 5 sets out our recommendations for guidelines.
Chapter 2 – Risks for Projects of Common Interest
2 INVENTORY OF POSSIBLE RISKS

This chapter reports on the task to take an inventory of possible risks for energy infrastructure projects. We specially focus on project risks for PCIs and regulatory risks, while also highlighting how risks for project promoters can result and how risks can potentially lead to delays or cancellations in projects being commissioned. In addition, we investigate the perceived levels of significance of regulatory risks, from the points of view of NRAs, TSOs and investors. In this way, the differences in stakeholders’ perceptions of risk levels are exposed, and the risk factors which can be considered as priorities to be addressed are identified.

2.1 Risk and higher risk than for comparable projects

In applying article 13 of the TEN-E regulation, it is essential to define what is meant by a risk for a promoter of a PCI. It is also essential to have at least a broad understanding of what is meant by risks that are higher than risks normally incurred by a comparable infrastructure project.

Risk

A PCI is subject to various project risks. Examples of project risks are permitting delays during the development phase of the investment, cost and time overruns during the construction phase, and cost overruns and technological failure during the operational phase of the investment. Depending on the exact moment in the investment’s lifetime, project risks could lead to a PCI being delayed (or even cancelled), becoming more costly than anticipated, or being frequently disrupted (or even early decommissioned). Project risks may therefore cause PCIs not (fully) realizing their expected net benefits, thereby causing concerns to the EC. The EC is particularly concerned about the (timely) delivery of PCIs.

For the purpose of developing policy implications regarding PCIs, we identify two broad categories of project risks:

- Risks related to the (technical) characteristics of PCIs, so-called project-specific risks; and
- Risks related to the institutional setting of PCIs, so-called systemic risks.

Project-specific risks are for example related to the technical lifetime of the infrastructure’s components, the time-out-of-use during the investment’s lifetime, and the uncertainty during the construction phase about the investment going to be commissioned at all. Systemic risks are for example related to adverse legislation, adverse regulatory decisions, and failure in coordinating major investments resulting in excess capacity and stranded assets.

The main difference between these two risk categories is that the former is to a large extent beyond the control of the public institutions, whereas the latter is generally under their control. We realize that this distinction is somewhat arbitrary. For instance, an NRA lacking credibility may not be able to effectively control the risk of adverse regulatory decisions overnight as it takes time to build up a track record. Nevertheless we consider this distinction to be a useful analytical device. To the extent that in practice some systemic risks are not controllable by the public authorities, they should be treated as project-specific risks for the purpose of designing effective regulatory incentives or measures.

A project promoter’s risk can be defined as uncertainty with respect to the project’s return on investment, the project’s revenue stream and the liquidity of the investment. In other words, the project promoter’s risk consists of uncertainty regarding the timing and amounts of the costs and revenues resulting from the project. In general, risks are examined in this study with regard to their potential to influence a project promoter not to take a positive final investment decision and
therefore not to proceed with developing or constructing a PCI. If, during the planning phase, the project promoter considers the risks to be too high, then he will not take a positive final investment decision and the project will not be developed or constructed. In such a case, users are exposed to welfare loss as they will be denied the availability of the project (assuming the project has net benefits for them). If risks in the form of time or cost overruns actually occur during the development and construction of a project, then the commissioning of the project will be delayed or the project may even not be commissioned at all. If risks in the form of technical problems actually occur when the project is in operation, then disruptions may occur or the project may even be early permanently decommissioned. Again, in such cases, users are exposed to welfare loss as they will be denied the availability of the project (assuming the project has net benefits for them).

Typically, not all project risks are also project promoter’s risks. For instance, deciding to cancel a project due to (expected) financing difficulties at an early stage, meaning before the project promoter has incurred any significant costs in terms of time and other resources or has made any significant commitments, is a project risk. Such a decision would however not constitute a real risk for the project promoter. Furthermore, in a regulated environment the applicable regulatory framework determines how project risks are split between the project promoter and the users. The assignment of risks between the project promoter and the users can be illustrated by the distribution of volume risk. Volume risk is related to the actual use of assets, which in turn determines the revenues of the project promoter. If demand for capacity is below the expected level, then the revenues of the project promoter will also be lower than expected, and will be insufficient to cover the costs (and vice versa). In case the project promoter carries the volume risk, it therefore faces the uncertainty of its revenues being insufficient to cover the costs or its revenues exceeding the costs. In case the users carry the volume risk, under- or over-recovery of costs by the project promoter in a specific year will lead to tariff increases or decreases in a subsequent year (or subsequent years) to compensate for any under- or over-recovery of costs in that specific year. It is also possible that volume risks are not borne entirely by the users of the infrastructure, but that volume risks may effectively be shared with the users of other infrastructure and/or by the wider tax-paying community.

Regulatory risks are project risks which can be influenced by the NRA’s regulatory framework. Regulatory risks mostly relate to uncertainties for project promoters with regard to cost recovery. Regulation is, however, not only a source of risk for project promoters, but also offers a way to deal with (part of) the risks resulting from other risk factors. In particular, regulation can distribute risks between the project promoter and the users of the infrastructure, as shown by the above mentioned example of volume risk. We have been asked to give specific attention to regulatory risks, as they are typically factors which may cause great concern, and which NRAs can generally affect.

Higher risk than for comparable projects

The TEN-E regulation does not define or explain what is meant by risks that are higher than risks normally incurred by a comparable infrastructure project. A PCI could be compared to other energy infrastructure projects delivered so far. It could be envisaged that such a comparison includes at least the size, technology, financial structure and location of the project. Some stakeholders expressed their confusion when asked to explain their understanding of “comparable projects”. Others referred to their past experience with investments in energy infrastructure. Further analysis of this issue is out of scope of this study.

In general, risks will be examined in this study with regard to their potential to influence a project promoter not to take a positive final investment decision and therefore not to proceed with developing or constructing a PCI. Identifying the
possible risks to which a PCI may be exposed, is a prerequisite for identifying the optimal design of potential regulatory incentives.

The above-described approach to analysing PCI risks is well-aligned with the conclusions of ACER’s Recommendation ‘On Incentives for Projects of Common Interest and on a Common Methodology for Risk Evaluation’ published on 27 June 2014 (Recommendation). Specifically, the Recommendation states that: ‘the information necessary to prove the existence of risk and to allow an assessment of its magnitude should be provided by project promoters. In particular, project promoters should indicate to NRAs the extent to which they are exposed to higher risks compared to the risks normally incurred by a comparable infrastructure project’². ACER’s rationale for placing the responsibility to demonstrate higher risks for PCIs (where that is indeed the case) on project promoters is based on the fact that project promoters are those best informed about the project’s features and aspects. In other words, they are the entity who understands the project in the greatest level of detail.

Categories of possible risk factors

Over thirty risk factors to which a PCI may be exposed have been identified. It should be noted that a project’s or a project promoter’s exposure to all of them is unlikely. This is first of all because risk factors vary from project to project. Also a project may be facing risks even though the project promoter has not yet incurred any costs or made any commitments, meaning that despite the project risks there is still nothing at stake for the project promoter when the project would for instance be cancelled. This could for instance be the case when the project is cancelled in an early stage due to difficulties in raising capital. Finally, the applicable regulatory framework may have transferred the project risks to the users of the infrastructure.

The identified risk factors have been divided into seven general categories, as described below. For each category it is explained to which phase of the investment cycle (development, construction, operation) these risks apply and how they may lead to project promoter’s risks, thereby potentially influencing the investment decision.

- Policy and Legal
  - Lack of proactive political support
  - Legal gaps or grey areas and poorly-defined laws
  - Uncertainty caused by delays in the transposition of EU law
  - Unpredictability of judiciary rulings

Policy and legal risks generally relate to uncertainty with respect to cost recovery over the whole lifetime of the investment. Lack of proactive political support and unpredictability of judicial rulings (on permitting issues) also create uncertainty regarding the turnaround time of the development and construction phase, and thereby uncertainty about the timing of future cash flows.

- Planning and permitting
  - Highly time-consuming, overly-complex or expensive permit application procedures
  - Bottleneck at the stage of public consultations
  - Local opposition which results in a delay to permits being granted or delays in project construction (delays may also occur during times following the completion of public consultations)

Planning and permitting risks create uncertainty regarding the turnaround time

² ACER, 2014. On incentives for projects of common interest and on a common methodology for risk evaluation. Recommendation No 03/2014
of the development phase, and thereby uncertainty about the timing of future cash flows. As it may sometimes be necessary to start construction before the permitting process has been completed (to make the commissioning date), planning and permitting risks may also lead to uncertainty regarding cost recovery (in addition to the uncertainty of reimbursement of the costs of permitting procedures themselves).

- **Regulation**
  - Changes in regulation, including direct intervention in cost recovery mechanisms (RAB, WACC etc.) and intervention affecting the load factors of the PCI (e.g. changes in capacity allocation rules)
  - Lack of sufficient cost recovery mechanisms
  - Insufficient assurance against volume/market risk
  - Lack of timely recognition of costs
  - Benchmarking based on non-comparable technologies / projects / conditions
  - Asymmetric treatment of PCIs within different regulatory frameworks

As said, regulatory risks are project risks which are influenced by the regulatory framework. These risks relate to uncertainty with respect to cost recovery over the whole lifetime of the investment as well as uncertainty with respect to the timing of future cash flows. Regulation obviously influences cost recovery in various ways. Differences between national regulatory frameworks leads to uncertainty about the way cross-border PCIs are treated from a regulatory perspective. Also recall that regulation is not only a source of risk, but also offers a way to deal with (part of) project promoters’ risks (resulting from other risk sources identified in this section). In particular, regulation can distribute risks between the project promoter and the users of the infrastructure.

- **Finance and capital markets**
  - Higher interest rates due to long project lifetime and financing period
  - Failure in ensuring adequate investment capital
  - Difficulties of project promoters in maintaining equilibrium (liquidity) on their balance sheets

Finance and capital market risks generally create uncertainty regarding the availability and cost of capital over the whole lifetime of the investment. Depending on the regulatory framework these could be project promoter’s risks, for instance when re-financing is required during the lifetime of the investment. But failure in ensuring initial investment capital can be a project promoter’s risk as well, namely in case ensuring capital imposes costs in terms of time and other resources on the project promoter.

- **Energy markets**
  - Competition with other projects, including PCIs
  - Changes in energy markets (e.g. fuel prices, market design, CO₂ allowances)
  - Uncertain demand forecast due to uncoordinated generation and transmission investment
  - Non-harmonised market arrangements between countries
  - Biased decision-making process due to bundled interests in generation and transmission assets

Energy market risks create uncertainty with respect to the actual use of infrastructure investments over the whole operational lifetime of the investment. Depending on the regulatory framework this could be a project promoter’s risk.
Technology
- Equipment failure
- Non-availability of technology or difficult access to technology

Technology risks mostly lead to uncertainty about the technical lifetime of the investment and the time-out-of-use during the investment’s lifetime, but also to uncertainty about the investment going to be commissioned at all. Obviously, these risks are higher for new technology than proven technology.

Geographic distribution of costs and benefits
- Controversial cross-border cost allocation
- Counterparty risks
- Asymmetry of resources or/and interests of stakeholders

Geographic distribution risks mainly create uncertainty about a successful commissioning of PCIs, or at least about the turnaround time of the development and construction phase (and thereby to uncertainty about the timing of future cash flows).

Views on the significance of risks

Project promoters’ views

Based on the interviews with project promoters and with reference to the ENTSO-E paper of 27 August 2013\(^3\) we note some general views of project promoters\(^4\) related to risks that project promoters (of PCIs) may be exposed to.

Most of the project promoters indicate risks that can be potentially higher for PCIs than for business as usual (BAU) projects. Such risks included many of the risks from the inventory presented above. The most recurring concerns included:

- Permitting risks (also with regard to land rights acquisition);
- Regulatory instability;
- Difficulties in raising capital;
- Lack of liquidity during the construction phase;
- Volume risks due to uncertain demand forecasts and potential competition between projects and infrastructure.

In addition, many individual TSOs emphasize that the complexity of cross-border projects is higher than for internal projects. That is why risks related to cross-border PCIs tend to be more extensive and varied in nature than risks for internal projects. A general feedback was that given the planned (PCI) investment volume across the EU, these risks are likely to become more relevant in the future than they have been so far.

The categories of risks identified by ENTSO-E (Regulatory, Legal, Permitting etc.) overlap broadly with the risk categories presented above. ENTSO-E has produced a radar graph (shown in Figure 1) that illustrates the level of risk per type of project and per risk category.

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\(^4\) Views of project promoters are mainly those of TSOs, investors, and entities decoupled from TSOs.
**Figure 1: TYNDP 2012 investment risks map**

![Radar graph showing investment risks](image)

*Source: ENTSO-E, An assessment of the risks of TYNDP 2012 projects*

This radar graph was produced based on a questionnaire among the ENTSO-E members and should be interpreted as follows. The level of risk depends on a type of project (internal, cross-border, off-shore, and business as usual (BAU)). Off-shore and cross-border PCIs are exposed to higher risks than other projects. Also, the risk level of BAU investment (non-TYNDP) is lower than for any other category of projects. Consequently, the risks related to BAU projects are not an “appropriate reference for all future projects”. ENTSO-E concludes that TYNDP projects have higher risk profiles than BUA projects and that the regulatory framework needs to adequately address these higher risks to ensure that the required investments can be financed in a changing investment environments.

**NRAs’ views**

Based on the interviews with NRAs and with reference to the CEER memo of 7 March 2014, we note some general views of the NRAs concerning risks related to (PCI) investments. These views refer broadly to the extent to which the regulation transfers risks from the project promoter to the users of the infrastructure and to the specific risks that PCIs may be exposed to.

**Regulation covers risks**

In the interviews several NRAs stated that risks are passed through to a significant extent to users, so they are not carried by the project promoter. In fact, most of regulatory frameworks in the EU member states allow for a significant pass through of risks. The remaining risks for project promoters are addressed in the regulation by including a risk premium in the allowed cost of capital. This (in most cases) uniform risk premium is meant to cover the average remaining risks. Individual investments can of course have higher or lower remaining risks.

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5 Corresponding with point 3 in section 2.2 of this report.
6 Corresponding with point 1 in section 2.2 of this report.
7 ENTSO-E, An assessment of the risks of TYNDP 2012 projects, 27 August 2013, p.3.
8 CEER, Regulatory aspects of energy investment conditions in European countries, 7 March 2014.
In this sense, the risks for project promoters depend less on a specific project, and more on the design of the regulatory framework. Therefore, even if a PCI is exposed to higher risks than comparable projects, this does not mean that these risks are not already covered by the regulation. The implication of this is that regulatory risk is very important in terms of whether projects will be developed or not.

Bearing in mind the fact that risks for project promoters are shaped primarily by regulatory framework design, ACER’s June 2014 Recommendation advises that: ‘after evaluating the existence and the nature of the risks, NRAs should assess whether (or not) the risks are already addressed by the existing regulatory frameworks, whether (or not) the risks are under the control of the project promoters and whether (or not) mitigation instruments other than regulatory incentives could be used (such as diversification, insurance, hedging and investment guarantees from national and multilateral agencies, etc.)’.2

Project risks
Apart from the general approach of downsizing the project promoter’s risks by means of the regulation, NRAs have identified some risks (“project risks”) that PCIs may be exposed to. These risks are mostly inherent to cross-border projects.

According to several NRAs, some project risks might stem from asymmetry of regulatory frameworks in cross-border projects. Such risk occurs for example if early recognition of costs is possible within the regime of one country, but is not an option in another country involved in the project delivery. Differences between national regulatory regimes lead to uncertainty about the way cross-border PCIs are going to be treated from a regulatory perspective, for instance with respect to cost recovery.

However, asymmetry of regulatory regimes shall not be tackled at any price. The NRAs which consider that some degree of risk might result from asymmetries of regulatory frameworks in cross-border projects also stress the importance of regulatory stability. They see a risk related to attempts to harmonise specific components of the regulatory frameworks at the EU level. Such intervention could upset the balance of the national regulatory regimes and thereby just put investments at risk.

Also, the NRAs mentioned project risks related to:

- Cross-border cost allocation (CBCA). For the PCIs which submit CBCAs, the outcome of the CBCA may be controversial, leading to uncertainty about a successful commissioning. The maximum timeframe for a PCI’s CBCA to be undertaken is defined by the Infrastructure Regulation; however, if in reality it is not possible to complete the process within the specified timeframe, this would create uncertainty about the timing of future cash flows.10
- Time-consuming, overly-complex or expensive permit application procedures. As explained above, permitting procedures can constitute a risk (unless the TEN-E regulation streamlines them sufficiently).
- Financial risks. Attracting sufficient investment capital in the future may become more difficult, especially for projects developed in Eastern and Central Europe.

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9 As put forward by the CEER memo of 7 March 2014, risks for project promoters shall be evaluated taking into account the existing risk-reward ratio in the regulatory framework and the final interest of the customers of energy networks.

10 Further explained in section 2.3 of this report (on distribution of costs)
Given the planned (PCI) investment volume across the EU, these project risks are likely to become more relevant in the future than they have been so far.

2.2 Risks and the investment cycle

This section discusses the views of stakeholders on the risk profiles during the different phases of the investment cycle, including planning and development, construction and operation.

The planning and development phase includes the securing of project financing. The possibility that debt and equity lenders perceive a PCI as being a high-risk investment opportunity (and hence are unwilling to lend, or only at a higher reward) will be real. This risk may also apply during the project operating phase in case the project has to be re-financed.

Many stakeholders point out that risks occurring during the development and construction phases are likely to be different from the risks in the operation phase. Most stakeholders indicate the development and construction phases to be most susceptible to expose the project promoters to risks. They referred especially to finance and permitting risks. On the one hand, a permit granting procedure that involves strong public participation may be over-complex and time-consuming. On the other hand, limited public participation may lead to delays because of granted permits being appealed or otherwise challenged. The raising of capital may not be straightforward due to uncertain regulatory framework and market forecasts.

During the operation phase, operators may be exposed to mainly finance, energy market and technology risks. Also ex post efficiency requirements deriving from regulatory regimes are considered to be relevant risks during the operation phase. These risks are usually difficult to predict for the entire operational lifetime of the assets. Maintenance risks during the operation phase are broadly related to OPEX overruns.

Typology of PCIs

It is important to understand the degree of vulnerability of PCI types to specific types of risks. The typology presented below facilitates such an understanding. It does not indicate whether the risk is higher or what is the probability that it will occur, the typology is included to the extent as it identifies particular risks for specific kinds of PCIs. PCIs can be grouped into different project types, based on several criteria. These criteria include:

- Geographic scope of the project (cross-border v. internal).
- Previous existence (Greenfield v. brownfield).
- Technology record (innovative v. proven).
- Investment scheme (regulated v. merchant).

1) Cross-border v. internal

All PCIs either physically cross (one or more) national border(s) and/or have significant cross-border impacts. PCIs are by nature cross-border because they always affect more than one country. Closer analysis of the cross-border dimension of a PCI requires taking into account:

- The geographic scope of the project; and
- The origin of project promoters.

11 It is worth noting that this effect would follow for both PCI and non-PCI projects in the event that a particular investment opportunity is viewed as being overall high-risk
In this regard three PCI types can be distinguished:

1. Projects that physically cross the border and are developed by project promoter(s) from only one country.
2. Projects that physically cross the border and are developed by project promoter(s) from more than one country.
3. Projects that physically do not cross the border and are developed by project promoter(s) from only one country.

Some risks for project promoters can occur only within cases 1 and 2 (cross-border PCIs). The risk types worthy of particular consideration in the cross-border v. internal context include:

a) Coordination between stakeholders

The larger the number of stakeholders, the more complex the investment process, especially in terms of coordinating approval granting.

b) Distribution of costs

Historically, the distribution of cross-border project costs was simple: each country paid for the assets on its territory\(^\text{12}\). Whilst this option remains available today, according to the TEN-E regulation some PCIs will be eligible for cross-border cost allocation (CBCA) that will be decided by the NRAs upon the request of the project promoter(s)\(^\text{13}\). NRAs deciding on CBCA shall take into account, among others, the economic, social and environmental costs and benefits. Given the complexity of the CBA in case of many PCIs (including the difficult assignment of money value to some benefits), there is a risk that the NRAs decision making process takes a longer period of time than that specified by the Infrastructure Regulation, and/or does not lead to satisfactory consensus. Controversial and/or lengthy CBCA will in turn affect the project promoters since the very beginning of project delivery.

c) Regulatory regimes

Regulatory remuneration of investments is subject to the decision-making of more than one NRA. This influences the remuneration’s consistency, stability and symmetry.

d) Levels of experience

Projects promoters and NRAs of different countries may not have the same level of experience, know-how or human resources to ensure the timely and efficient delivery of infrastructure projects. This can be a potential source of risk if the synergy between the involved parties does not occur.

e) Legal frameworks

Cross-border projects involving non-EU countries will have to deal with different legal regimes (as opposed to internal projects). No common legislation except for

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\(^\text{12}\) L. Meeus, Xian He, Guidance for Project Promoters and Regulators for the Cross-Border Cost Allocation of Projects of Common Interest, Florence School of Regulation, January 2014.

\(^\text{13}\) According to the TEN-E regulation, a PCI is eligible for CBCA when an assessment of market demand or of effects on the tariffs shows that costs cannot be expected to be recovered by the tariffs.
international law and obligations deriving from bi- or multilateral agreements will apply.

f) Country-specific issues

Several country-specific issues may influence the delivery of cross-border projects. Some of them may be difficult to recognize. The most important such issues include:

- Internal generation capacity;
- Interest in generation assets;
- Exposure to loop flow;
- Energy price regulation;
- Energy mix portfolio;
- Transit opportunities;
- Stability of the economy; and
- The size and relative economic wealth of a country.

All of these issues shall be taken into account while assessing PCIs’ potential risks. Capabilities and levels of willingness to handle cross-border and large-scale investments may not be the same in all countries.

g) Permit-granting procedures

The investment approval process, including environmental impact assessments, tends to be more difficult to coordinate in cross-border projects than in case of internal ones.

2) Greenfield v. brownfield

Some PCIs involve building infrastructure in locations where there is no previously history of development (Greenfield). Other PCIs involve replacing and/or modernizing existing assets; these are brownfield developments. There is also a category of projects that involve both: modernization and expansion\(^\text{14}\). Risks can be assessed in relation to a given PCI’s level of:

a) Urgency

New (Greenfield) investments are rarely required on a “now or never” basis, so there is a temptation to defer final investment decision making. Investment decisions depend largely on the welfare increase anticipated to follow once the project is commissioned. Demand associated with new investments may be more elastic than demand for existing assets requiring replacement. Higher levels of demand elasticity can create greater market (volume) risk.

b) Public acceptance

In the case of greenfield projects there may be increased problems with gaining public acceptance as new land/sea surface (including environmental resources) is affected. This is also related to the risk of delaying investment due to more complex permit granting including environmental impact assessment and public participation issues.

c) Costs of capital (capex)

\(^\text{14}\) For instance the PCI of the Incukalns Underground Gas Storage (Aquifer storage facility in Latvia).
Uncertain infrastructure costs constitute a higher risk in case of new/expansion than in case of replacement projects. The utilization of new project infrastructure depends on market forecasts. Forecasts of market demand and supply issues are uncertain especially in the transmission sector. In the case of new investment the lack of information might impede, to an even greater extent, the achievement of a credible and accurate estimation of the costs than in the case of replacement projects. Also, new/expansion projects tend to be larger in scale than replacement ones. A project-specific CBA may not be able to sufficiently cover this uncertainty due to lack of accurate data and experience. Financial investors find it difficult to come up with reliable due diligence. Hence, attracting investment capital might be more difficult in the case of new/expansion projects than in the case of replacement ones.

3) Innovative vs. proven technology

Some of the listed PCIs can be classified as “traditional” as they involve the use of proven technology, for which there is a long experience and reliable information. Other projects engage innovative, new technology for which there is no documented experience in terms of scale, duration or other technical aspects (e.g. off-shore hubs). These differences could be analyzed not only in absolute terms but also with regard to the concrete project promoter's experience and access to know-how. The innovation in this context is not about lowering the investment cost, but has to do with application of technologies that have not yet a long use record and experience of using them is relatively short. The difference in risks for PCIs depending on the technology they involve is mainly related to:

a) Operating expenses (OPEX)

The use of new or unconventional technologies creates more OPEX-risks. It is important to note this because OPEX generally fall under the controllable costs and hence directly impact project promoter's regulated revenue. OPEX rise as innovative technologies require higher funds allocated to research and development than proven technologies. Due to uncertain maintenance requirements some OPEX costs might be difficult to predict – and higher in case of miscalculations. It refers among others to wages to the employees for maintenance, equipment replacement, and frequency of maintaining activities.

b) Costs of capital (CAPEX)

The risk related to CAPEX might be higher in case of innovative technology investment than in case of proven technology investments. In general developing a project that is first of a kind is exposed to scarcity of information that is crucial for credible and accurate estimation of the costs. Optimal values of the rate of return for innovative technology investments are therefore difficult to establish. For example, if innovative technology is used, then the life of the assets might occur to be shorter than initially expected. There is also a risk that sinking investment will be done prematurely in technologies that later turn out to be inefficient.

c) Experience

Innovative technologies applied in a project may further increase the risk due to lack of experience of such project’s promoter and the NRAs. Such a deficiency may

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15 For example, in the case of LNG terminals liquefaction, shipping, regasification costs are higher than the costs of traditional pipelines operation. The same trend applies for off-shore and on-shore wind farms. Underground gas storage opex refer to proper recycling of the working gas and using new technical procedures to better understand reservoir geology, confinement and reservoir flow behaviours. These are site and technology specific costs and tend to be usually higher than in case of traditional storage system.
discourage the project promoter and delay the procedures within the NRAs. There is therefore higher risk of delaying or deferring a project based on innovative technology than it is in case of a replacement project.

4) Regulated investment scheme vs. merchant investment scheme

Merchant scheme investments are profit motivated developed by the project promoter that is legally separated from the TSO. Investment schemes developed by the TSOs are conducted within the regime of regulated tariffs. Risk-profile for each type of scheme is not identical. Differences may occur in relation to:

a) Remuneration

Usually, as in the case of interconnectors, the remuneration depends both on the exemptions from third party access guaranteed over the period (to allow a return for both debt and equity providers), and the degree of market (volume) risk which the project encounters.\(^\text{16}\) That is, the return which a project promoter receives is shaped by the degree of use of the asset.

Risk on merchant project promoters stems from price and volume trends driven by market demand for capacity and price set by auctions. In merchant based interconnectors, remuneration and recovery of revenue losses for the project promoters is done via charges levied on users of the interconnector mostly through congestion rents. For merchant investments exemptions from the Third Energy Package rules (i.e. TPA) are possible. Projects exempted from these rules are not eligible for incentives granted according to article 13 of the TEN-E regulation.

In a cross-border merchant scheme investment rent sharing between the countries could be complicated. Remuneration with the regulated investment scheme relies mostly on national transmission tariffs.

b) Regulation

The regulatory risk is by definition different for merchant investments and regulated investments because the former are partly or totally exempted from regulation. On the other hand, they have much higher market risk. In fact, the exemption could be considered as a specific regulatory treatment as meant in the TEN-E Regulation. The remaining risk profile of merchant investments v. regulated investment is not different by definition (although it could be). In general, a merchant project promoter´s willingness to develop a project shows that the particular project´s revenue-related risks do not threaten its timely-development\(^\text{17}\).

There is also a third type of investment schemes. It is intermediary between the two above-mentioned schemes based on providing a certain degree of regulatory security to merchant based investments (e.g. cap and floor regime). This (cap and floor) regulatory approach is currently under development by the UK and Belgian regulators, to provide a joint regulated route for delivering the NEMO Interconnection between Belgium and the United Kingdom. It is also serving as a

\(^{16}\) ElecLink Limited, Application for EU exemption for a new interconnector between France and Great Britain, August 2013.

\(^{17}\) K. Perrakis, Regulatory aspects and EU experiences of power interconnections, Brussels 2011.
pilot for a regulated route for other interconnector investments connecting to the United Kingdom.\textsuperscript{18}

Its application is justified in case the exemptions to the relevant Third Energy Package rules and restriction on capacity allocation cannot be applied, but the commercial interest of merchant developers can sufficiently drive the investment development. The risks for project promoters in this "hybrid" investment scheme depend on the width of range between the cap and the floor on returns.

2.3 Regulatory risks to PCIs

Here we focus on regulatory risks only, providing a detailed list and discussing the perceptions of risk intensity for different aspects of regulatory risk.

As said above, regulatory risks are project risks which can be influenced by the regulatory framework. They occur when decisions taken by the NRA influence the rate of return of the project and/or affect the project stream of revenues. These risks relate to uncertainty with respect to cost recovery over the whole lifetime of the investment. They also relate to uncertainty with respect to the timing of future cash flows. So regulatory risks originate from decisions by the NRA affecting:

- The rate of return (rate of return risk); and/or
- The cash flow (liquidity risk).

The impacts of any such decisions relates to whether they were anticipated or foreseen, and therefore whether any contingency arrangements may have been made. This can also be understood as stakeholders’ perceptions of the likelihood that changes would be implemented.

A rate of return risk occurs where the rate of return of the project is in danger: the project promoter is not eligible/certain to recover its investment, including the cost of debt/equity, through tariffs (user-pays approach). It is the risk for promoters not to receive back their invested money. In practice this means that they do not recover either investment costs (i.e. actual costs are higher than costs approved by the regulator) or the price for debt and the return on equity. Some stakeholders reported that they had experienced changes in the allowed revenues, and consequently they did not fully recover incurred costs.

On the other hand, liquidity risk hinders the ability of the project promoter to match pay-back requirements due to lack of timely and early recognition of costs. This risk occurs when regulation does not reimburse at the pace that is needed to keep up with cash flowing out. That is, he promoter is not getting the money at a pace that is satisfactory enough for equity investors and/or lenders. Stakeholders highlighted that the regulatory approval of costs is not the only solution, as timing matters: an inadequate stream of revenues after the investment decision threatens the promoters’ economic viability in carrying out the project. It has been argued that not enough cash flow coming from the tariffs may lead to a higher debt requirement, and this will be at a higher interest rate, and is therefore undesirable. Liquidity risk may be especially relevant when the project is not corporate/balance sheet financed. Liquidity risk may be triggered by a time overrun, i.e. postponing deadlines in the project’s schedule.

Hereafter we refer to regulation related risks only and describe these in some detail. The following risks related to the NRAs’ regulations have turned out to be the most

\textsuperscript{18} Whilst the cap and floor regime for the NEMO Interconnector is still under development, a decision has been made to roll-out cap and floor regulation for other near-term interconnector projects in the United Kingdom. This decision and regulation is discussed in greater detail later in this report.
significant in the course of this project, where “significance” reflects the intensity with which stakeholders (including NRAs, TSOs, investors and network users associations) have put these risks forward in the course of this project (during interviews, the workshops held on 5 March and 23 June, and through questionnaires). A copy of the assignment stakeholder questionnaire is included in Annex 1.

Please note that the order in which the above risks are mentioned does not reflect a specific priority; the intensity for each risk type will be discussed below.

The list of regulatory risks is as follow:

- **Unrecovered operational cost overruns (OPEX risk).** Operational cost overruns during the lifetime of investments not being reimbursed.
- **Under-recovery of specific investment costs:** some costs (such as the upfront fees commonly charged within the process of securing project financing) may not be included within the group of allowed recoverable costs. This can undermine full-cost recovery, particularly in situations where securing project financing is very challenging.
- **Under-recovery of construction phase costs:** the regulation not reimbursing (all) costs incurred during the construction phase. There is no guarantee for the recovery of development costs.
- **Investments ex post (after commissioning) may be declared inefficient,** for instance when a (not-adequate) benchmark is applied as part of the regulation. Benchmarking based on non-comparable technologies/projects/conditions leads to unrecovered cost overrun.
- **Inadequate depreciation period.** When the regulatory depreciation period is too long compared to the actual useful lifetime of asset, investments become stranded during their lifetime.
- **Insufficient assurance against market risk or volume risk.** Market or volume risk occurs when demand for the services of the assets developed by the project promoter become inadequate (i.e. investments become stranded) and the missing revenue is not covered by the regulated tariffs or other sources as project promoters carry volume risk. Lack of sufficient cost recovery mechanisms against market risk may lead to an unbearable level of risk in terms of unrecovered cost overruns.
- **Delay in cashing-in regulated revenues,** including delayed recovery of construction phase costs, causing cash flow difficulties for the project promoter. In particular, in case lead times are long and pre-commissioning costs can be recovered only through tariffs during the operational phase, this may result in a liquidity risk.
- **Insufficient allowed cost of capital (insufficient rate of return).** This risk is related to the methods used by the NRAs to determine the allowed cost of capital, i.e. the regulatory rate of return. This may cause difficulties in persuading financial partners to agree on appropriate financing conditions and issues in finding financing, in particular when the project is not balance sheet financed and it needs to find equity investors. Stakeholders pointed out that this is relevant in a context where future investment volumes will require significantly more equity to be raised as companies’ cashflows, especially in the case of small TSOs who pursue big projects, do not provide a sufficient basis for funding large investment programmes. An insufficient rate of return may not attract money from bank lenders. The view of one investor was that the greenfield projects in order to be financed need a higher rate of return which compensates what is perceived to be a higher risk.
- **Cross-border coordination issues.** This risk deals with inconsistency between regulatory regimes. In particular inconsistencies and uncertainty may emerge with respect to:
- investment costs incurred in country A that, according to the CBCA, will have to be included in country B’s regulation or vice versa
- the timetable of the payments and cost recovery, agreed to in the CBCA
- cross-border PCIs, for instance with respect to cost recovery
- more than one regulatory regime leading to additional risk for cash payments
- higher likelihood of potential influence by governments
- Unsuccessful coordination possibly leading to cost under-recovery and cash flow difficulties.

- **Future adverse regulatory decisions.** This relates to the risk that future decisions within new regulatory regimes may counter the risk mitigation measures undertaken under the current regime or measures undertaken for the implementation of Article 13 of Regulation 347/2013. Future adverse regulatory decisions include direct intervention in cost recovery mechanisms (RAB, WACC, etc.) and intervention affecting the load factors of the PCI (e.g. changes in capacity allocation rules). It applies also when a regulatory framework is still not yet in place, such as in the case of offshore connection platforms. It matters because project promoters commit for an investment across different regulatory periods: the economic lifetime of assets is generally longer than regulatory period cycles.

Most of the risks included in the present list may be connected to the five categories of risks ACER recommends to use for identifying the nature of risk from a regulatory point of view, namely:

- The risk of cost overruns;
- The risk of time overruns;
- The risk of stranded assets;
- Risks related to the identification of efficiently-incurred costs; and
- Liquidity risk.

The Recommendation recognizes also the relevance of cross border issues (in the form of inconsistency between national regulatory framework), but left this issue for separate future investigation.

**Perceptions of risk intensity for each regulatory risk type**

The risk related to regulation that was mentioned with the highest intensity in the course of this project\(^{19}\) was that of cross-border coordination. In fact there is a broad consensus over different stakeholder categories on the fact that cross-border coordination issues represent a serious risk. Few stakeholders disagree on this; however, only a minority classifies this is an overwhelming risk.

Risk of future adverse regulatory decisions ranks as the second most worrisome risk after cross-border coordination. Uncertainty about future (beyond the current regulatory period) regulation (and thereby uncertainty about the future rate of return on investments) was also often mentioned during interviews by TSOs and investors. TSOs highlighted that this concerns all regulated projects, not just PCIs, as investors are looking for stable returns. The fact that a project may be declared inefficient by the Regulator in the future is also a big disincentive for investors. TSOs pointed to the fact that the change may also affect past investments (retroactive decisions). This risk was stressed by project promoters involved in gas infrastructure, which frequently have very long lifetimes. NRAs have a more diversified view on this. One argument challenging this view that has been put forward is that most changes are due to policy, not due to regulation. As far as future regulatory decisions are concerned,

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\(^{19}\) During interviews, the workshops held on 5 March and 23 June, and through questionnaires, whose results on regulatory risks to PCI are presented in Figure 2
NRAs pointed out that they are committed not to change regulation suddenly and radically, as reliability and transparency are among their principles.

A comparison of perceptions of the severity of regulatory risks to PCIs’ timely development, when all stakeholder types are considered together, is provided in Figure 2.

**Figure 2: Stakeholders’ perceptions of the severity of regulatory risks to PCIs’ timely delivery (% of stakeholder responses)**

![Stakeholders' perceptions of the severity of regulatory risks to PCIs’ timely delivery](image)

Views on financing risk²⁰ seriousness vary among stakeholders. The financing issue is perceived as being slightly more problematic in Eastern Europe and it appears to be a more relevant concern for gas business. In fact, half of electricity TSOs who responded to the questionnaire mentioned financial risk as a serious or overwhelming problem, while the remaining ones deemed the risk level as limited. In contrast, 80% of gas TSOs consider financial risk as a serious or overwhelming problem. Finally, the financial issue is regarded as more serious in Eastern Europe: almost 80% of institutions based in Eastern Europe who responded to the questionnaire regarded financial issues as more than serious. By comparison, the percentage is 30% for institutions based in Western Europe.

Feedback from stakeholders confirmed the difficulty in obtaining adequate financing in Eastern Europe and particularly in accessing capital markets. The main reasons for this include:

- Frequently, TSOs are state-owned and it may be difficult to raise equity from the Member States due to budget constraints;
- TSOs are in the early stages of liberalization and therefore do not have long credit histories and long-term experience. Hence, they have lower visibilities; and
- Higher premiums requested by investors (possibly due to country risk).

²⁰ Financial risk maybe linked to regulation but regulation is not the only factor generating financial risk.
Insufficient allowed cost of capital was mentioned especially for new projects, which are in danger of not being undertaken as replacement investments are the easiest choice when the rate of the return is the same. Some stakeholders pointed out that, for the purpose of quantifying financial risk, it matters whether the assessment is made at corporate level or at project level.

Cash flow difficulties are generally regarded as limited, also in Eastern Europe. However, the risk was signalled as a serious issue for gas projects. Investors commented that cash flow difficulties can be addressed by the design of the financing structure.

The perceived seriousness of cost under-recovery and time-overruns varies across stakeholders: this reflects the difference depending on regulatory framework. This confirms that some factors can represent a big risk in a few countries and not be a problem in others. According to an investor’s view, time overrun should be covered by an Engineering, Procurement, and Construction (EPC) contractor guarantee. As concerns the under-recovery of operating costs, many stakeholders commented that this risk is typically related to new technology investments, as operational costs are more difficult to predict, but could also be due to tighter production factor markets. Benchmarking was mentioned as a serious source of under-recovery. The benchmarking of new technologies may be controversial if there is a lack of previous experience in new technology benchmarking, because costs may be considered as being unreasonably high.

Market risk is perceived as far more significant for those involved in gas projects, to a lesser extent by electricity TSOs and even less for NRAs. Some gas TSOs regarded market risk as overwhelming; this view may be explained also by the current lack of long term commitment for infrastructures and the changes in flows affecting rate of utilization of gas pipelines. It was highlighted that PCIs are potentially linked to security of supply, so the problem of potential under-utilization of infrastructures emerges, entailing an apparent risk of stranded assets.

Focusing on TSO’s responses to the questionnaire only (shown in Figure 3), there is considerable variation in the perceptions of different TSOs regarding the severity of each risk type.

This is likely a result of different TSOs’ means of measuring and quantifying risk levels. Member States’ TSOs will likely also face different challenges in developing infrastructure projects related to their specific national (and immediate neighbouring country) context. However, the majority of TSOs agree that cross-border coordination issues, unrecovered cost overruns, future adverse regulatory decisions and time overruns are serious risks. Various TSOs also consider that certain risks are overwhelming, indicating their view that the use of targeted and effective measures to address those risks is crucial. In particular, 25% of TSOs consider that the risks of time overruns, unrecovered cost overruns, cash flow difficulties and market-related risks are overwhelming. However, the risk factors which are viewed as being most severe are future regulatory decisions and, especially for gas TSOs, financing issues. Specifically, around one third of all TSOs view these two risk categories as overwhelming.

21 However, an exception to this general trend is that, within this study, one TSO commented that cash flow difficulties was the most important issue it faced in relation to realising timely investments
Figure 3: TSOs’ perceptions of the severity of regulatory risks to PCIs’ timely delivery

The views of NRA respondents to the questionnaire are shown (in aggregate form) in Figure 4. Compared to the views held by TSOs, it is clear that NRAs consider that PCIs face lower levels of risk of delay or cancellation. In contrast to TSOs’ views, NRAs generally do not consider risk levels to be overwhelming (although cash flow difficulties and financing issues were exceptional cases, with one NRA in each instance considering those risk levels as overwhelming). As was also generally the case with TSOs, the majority (more than three quarters) of NRAs viewed cross-border coordination issues as a serious risk.

Figure 4: NRAs’ perceptions of the severity of regulatory risks to PCIs’ timely delivery

The second major point that is immediately clear is that, as was also the case with TSOs’ responses to the questionnaire, NRAs as a group demonstrate significant variation in their views on risk levels; in other words, there does not appear to be any uniform and shared view on risk levels. This may again be due to differences in individual NRAs’ experiences and prevailing circumstances, and the use of different risk analysis tools.
2.4 Conclusion

In this section of the report we have set out the findings of our analysis relating to risks for PCIs being timely developed. In particular, we have taken a comprehensive inventory of factors leading to risks for project promoters. We then focused in with a greater degree of detail on regulatory risks impacting on projects. Regulatory risks were given specific attention as they are generally factors which NRAs have clear control over, and can therefore be addressed in a straightforward way. In general, such risks mostly relate to uncertainties for project developers with regard to cost recovery over the whole lifetime of a project. In the PCI context where projects are typically cross-border in nature, differences between national regulatory frameworks result in further uncertainty in the way projects are treated from a regulatory perspective (and hence uncertainty concerning investment cost recovery).

A risk typology of PCIs has also been considered, wherein our analysis sought to relate specific types of PCIs to specific risk types. Specifically, the risk typology splits PCIs into four categories, based on:

1. The geographic scope of the project: whether the project is cross-border, or ’internal’ (that is, located only in one country);
2. The previous existence of the project: whether it is a new / expansion project, or a replacement;
3. The specifics (development record) of the technology being used by the PCI: whether the technology is innovative, or proven; and
4. The investment scheme used by the PCI: whether the investment is regulated, or merchant, in nature.

Based on the outputs of analyses, extensive interviews, workshops and feedback received from a stakeholder questionnaire, it has been possible to gain a detailed insight into the views of PCI stakeholders (NRAs, project developers/TSOs, investors) on the significance of the regulatory risks faced by PCI project promoters. NRAs and project promoters clearly hold distinct views on the significance of risks faced by PCI project promoters. Compared to TSOs (project promoters), NRAs consider that project promoters face relatively low levels of regulatory risk; this contrasts to TSOs, which view regulatory risks as being relatively more severe. In other words, NRAs consider that the risk level of PCIs not being timely developed is relatively low, whereas TSOs believe the risk of project delay to be relatively high.

The analysis has also shown, however, that within the respective NRA and TSO groups, there does not seem to be single and unanimously held view on regulatory risk significance. For instance, some NRAs consider financing issues to be a risk of overwhelming significance, whereas other NRAs consider that financing issues do not pose any risk at all.

A similar broad dispersion of views also exists within the TSO group. Differences in risk perceptions – both within and between stakeholder groups – may result from differences in (amongst other things) the country-specific situation in which the NRA or TSO is located, subjective differences in perceptions of thresholds of each risk level, and variations between stakeholders in their perceptions of the effectiveness of existing country-specific regulatory arrangements in place to address risks.

The feedback received from stakeholders showed that the most significant regulatory risks seem to be:

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22 We were requested by the Commission to focus mainly on regulation-related risks within our overall risk analysis.
Cross-border coordination issues;^23 Future adverse regulatory decisions; and Financing issues.

It is interesting to note that cross-border coordination issues are not only considered significant by TSOs and project developers, but also by NRAs. This highlights the fact that (some) NRAs have experienced and/or foresee considerable challenges in coordinating with the neighbouring country’s NRA in the PCI context. This may be due to NRAs’ (low) expectations regarding the NRAs’ abilities to find regulatory framework solutions that are acceptable to both parties and in some cases may result from previous experience.

In order to maximise the effectiveness of future efforts to address regulatory risks for PCIs, and hence to minimise the risk of PCIs being delayed or cancelled, our recommendation is that the three regulatory risks identified as being the most significant should be borne in mind. In other words, risks related to cross-border coordination, future adverse regulatory decisions and financing issues should be treated as a priority when considering the most optimal regulatory incentives to be implemented.

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^23 Some of the cross-border coordination issues are regulatory in nature, including the challenges and obstacles to aligning two or more countries’ regulatory frameworks for a PCI. This would include, for example, issues encountered in two or more NRAs reaching agreement on the payment terms, including in particular the timetable of payments - of regulated returns on investment of a PCI investment.
Chapter 3 – Methodology and criteria to evaluate investment risks in electricity and gas projects
3. METHODOLOGY AND CRITERIA TO EVALUATE INVESTMENT RISKS IN ELECTRICITY AND GAS PROJECTS

This chapter addresses the issue of evaluation of investment risks in energy infrastructure projects. More specifically, the aim of this task is:

(1) To make an inventory of methodologies existing in the different Member States to evaluate investments and their respective risks; starting from the submissions of NRAs pursuant to article 13.4 of the TEN-E Regulation.

(2) To identify the best solution(s) from the input provided by the NRAs, and, if necessary, propose additional solutions for the evaluation of investment risk in electricity and gas projects.

Section 3.1 presents the main results of the analysis of the submissions and the information and comments we gathered during the interviews and meetings with the stakeholders. In section 3.2, we assess and discuss the results, with a view to identifying any suitable practice already in place and – if necessary – understanding whether and why such practices are not available or adequate. Eventually (in section 3.3), we outline proposals for a best approach to risk assessment, as a basis for the provision of a suitable regulatory treatment, as required by article 13 of the TEN-E regulation.

3.1 Review of the status of NRAs’ development of risk evaluation tools

In July 2013, ACER has requested NRAs to submit the methodology and criteria used to evaluate investments, pursuant to article 13 of the TEN-E Regulation. The request was based on a Template, aided by examples, and consisting of two parts: the former focusing on the regulatory regime and the methodology to evaluate investments with particular reference to PCIs and their higher risks; the latter focusing on incentives.

This chapter considers the methodologies used for investment and risk evaluation, mostly based on answers provided to the request: “Please describe your methodology and the criteria used to evaluate investments in electricity/gas infrastructure projects and the higher risks incurred by them”.

Our review of the submissions and the interviews with stakeholders show that:

(1) In general, there are no explicit methodologies specifically aimed at evaluating the risk profile of a single infrastructure project, including PCIs (see Annex 2).

(2) The typical approach is to consider the regulated company’s business (and its risk) as a whole, rather than focusing on its single projects/assets. In other words, risk is estimated at activity or corporate level, rather than for single projects. A NRA clearly stated that “they do not consider risks at a project level, but rather they assess the risk of the project promoter’s business”.

Our findings are consistent with ACER’s Recommendation, which reads: “According to the information submitted by NRAs, the methodologies to evaluate the higher risks faced by project promoters are generally applied in the Member States (MSs) in the context of a portfolio risk profile of a TSO or other project promoters”\textsuperscript{24}.

The lack of an explicit methodology to assess project risk

As mentioned above, we found that in general there are no explicit methodologies specifically aimed at evaluating the risk profile of a single infrastructure project, including that of PCIs\(^\text{25}\) (Annex 2).

In fact, several NRAs indicate that their role related to new investments is focused on the efficiency of the costs incurred for the project, rather than on project risks. According to the NRAs’ submissions, in the majority of Member States the technical analysis of the new investments is prepared by the TSOs, which explain the need for the new infrastructure, and is possibly assessed by regulators\(^\text{26}\). Yet all these provisions are aimed at enhancing the transparency of the TSO’s decision-making process rather than at surrogating the NRA as the decision making / evaluating body.

In several cases, the project cost evaluation is performed by means of benchmarks, with 13 out of 30 NRAs reporting some use of benchmarking or efficiency schemes\(^\text{27}\) for electricity and 8 out of 29 for gas. In this respect, regulators are often aware of their limited capability to assess the efficiency of the investment costs incurred by the TSO. Technical and input market expertise that is used to estimate standard costs as well as benchmarking techniques may help, but regulators know that their ability to evaluate investments is limited, as NRAs do not always have access to full information because the specific conditions change in each case. For both electricity and gas, this is less true in distribution, but it is particularly true in transmission and storage, where most PCIs belong, and where few comparable cases can be identified within each country so that international samples are often necessary, but hardly used due to difficulties in comparing rather different countries.

Due to their limited risk assessment expertise, regulators may perceive investment costs as stated by TSOs as often excessive and possibly expensive. This risk, known as “gold plating”, may be perceived by regulators as serious even in the case of costs that are incurred as a way of mitigating higher risks. For example, suppose that the difficulty of obtaining permits for a new overhead HV line in a densely populated area is eased by accepting the requests of local authorities to avoid the critical area through a longer routing or by laying an underground cable. The case may also lead to a delay of the whole project, triggering further cost overruns. In such a case, the TSO would feel that the risk is higher, as it fears that not all costs will be accepted by the regulator and included in the RAB\(^\text{28}\). On the other hand, the regulator can hardly agree ex-ante that all costs would be accepted, as it would abdicate to its main duties.

Other reasons help to explain the lack of an explicit methodology for project risk assessment.

\(^{25}\) Notwithstanding this prevalent approach, several countries envisage a specific treatment for special projects, usually including major interconnectors, and may require a special analysis for them (e.g. Ireland). In such cases investment costs may also be excluded from benchmarking (e.g. Spain).

\(^{26}\) In a few cases, the investments must be part of a national plan or be approved by the Ministry in charge (e.g. the Netherlands, Spain). Public consultations on new proposals may also be required.

\(^{27}\) Some NRAs do not explicitly mention use of benchmarking or standard cost techniques, therefore it is likely that more NRAs may use similar approaches but have not reported them in their answers.

\(^{28}\) A case that was mentioned by TSOs and financial institutions is that of investments that are based in a country “A”, but whose costs should be borne by the users of country “B” pursuant to the principle that cost sharing should follow the distribution of benefits. Some times NRAs are reported as unable to provide assurance that such costs will be covered. Other similar uncertainties are also reported.
In its Recommendation, ACER, after recognising that currently NRAs do not generally assess the specific risk of individual investment projects, notes that “the general approach adopted by NRAs 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 project promoter through diversification”\(^{29}\).

In the course of this project, NRAs observed that the operation of the network is mostly unitary, and argued that individual components can hardly be evaluated “stand alone”. Hence the risk should be evaluated on a company (TSO) basis, as the CAPM does (see next section).

It was also reported that, in some cases, the regulators may not be equipped to evaluate in detail a certain new asset. In a few cases, external expertise (like that of a technical university or consultant) is sought for the technical assessment supporting the decision. In other cases, the investment decision is sanctioned by other authorities (e.g. the relevant Ministry) and/or is subject to public consultation, allowing stakeholders as well as technical experts to have a say and trigger an in-depth review if necessary. It is also worth noting that the typical staffing of European NRAs is not adequate for an in-depth analysis of investment benefits and costs\(^{30}\). NRAs may have few resources and probably are not even willing to become an investment analysis commission\(^{31}\). However, other NRA representatives argued that many NRAs do offer broad experience and know-how regarding the evaluation of energy infrastructure projects, derived from national network development plans, while currently it appears that no centralized EU agency does offer relevant experience and human resources.

Another point that was raised is that asymmetric information increases the difficulty NRAs have to correctly assess risk. The issue of asymmetric information between regulators and companies is likely to be more severe where projects are “different” from the usual ones, for example due to their international span or innovative use of technology, as is more often the case of PCIs.

Limitation of regulatory responsibilities in the assessment of investments is also seen as consistent with modern approaches to independent regulations, whereas their decisions should be limited to a few important ones, which (a) can be subject to a transparent process; (b) are carried out by several agents with no exclusive responsibility, and (c) are based as much as possible on objective methodologies. On the contrary, multiplication of decisions as required by the individual evaluation of single investments would reduce the transparency, accountability and objectivity of the assessment.

When dealing with risk evaluation, NRAs noticed that the typical risks for project promoters translate to the delayed implementation and the (often-related) cost overruns; however, in many cases these costs do not fall on the TSO (and therefore there is no project risk) as higher costs and interests on works in progress are eventually included in the asset base\(^{32}\). In several cases, the liquidity risk is also

\(^{29}\) \textit{Ibidem}, P.3.

\(^{30}\) U.S. Public Utility Commissions do it within a different regulatory framework, and are endowed with proportionally much larger staff for the purpose.

\(^{31}\) As an NRA representative said in the interview, “We don’t want to become another Gosplan”.

\(^{32}\) Usually TSOs oppose this argument by noting that the time dimension matters. Cash flow timing may be crucial: recovering costs in 10 years is not the same as recovering costs in 30 years, as regulatory regime may
mitigated by means of including work in progress in the RAB on a provisional basis, subject to actual completion and commissioning of the assets.

Some regulators question that PCIs may have higher risk than other projects. They point to the technical similarity of (most) PCIs with existing or new investments, and to the fact that the fast track procedures envisaged by the TEN-E Regulation would rather reduce risk with respect to (technically comparable) domestic projects. In their opinion, PCIs may even be less risky, due to procedural advantages foreseen by the TEN-E Regulation, like streamlined permitting procedures. Another stakeholder stated that PCIs are less risky thanks to the fact that they are generally better conceived and prepared, as well as commanding more political support. Political pressure to carry out the project may also give the TSO stronger bargaining power when negotiating with the NRA.

**The typical approach to evaluating risk**

Most NRAs\(^\text{33}\) calculate the allowed rate of return on assets using the Capital Asset Pricing Model (CAPM). In this method, the usual way of considering “corporate risk” is the beta factor that is part of the calculation of the Weighted Average Cost of Capital (WACC), and applies to the Regulated Asset Base (RAB). In this approach, the WACC is typically calculated as:

\[
\text{WACC} = \frac{K_E}{1-t_e} \cdot \frac{E}{D+E} + K_D \cdot \frac{D}{D+E} \cdot (1-t)\]

Where:

- \(K_E = r_f + \beta \times \text{MRP}\) is the cost of equity
- MRP is the Market Risk Premium
- \(K_D\) is the cost of debt
- \(t\) is the debt tax shield
- \(t_e\) is the corporate tax rate
- \(D\) is debt
- \(E\) is equity

The beta (\(\beta\)) provides a measure of the corporate risk, that is the risk of investing in the industry, and can therefore also be regarded as the average risk measure of “comparable” investments of the industry or, as said in the Recommendation, as the level of systematic risk for the overall activity\(^\text{34}\).

In fact, the beta factor of a company is an investment finance concept. It is calculated as the covariance of its share price with the average price of shares (represented by a stock market price index). TSOs and other regulated companies usually enjoy a regulated regime that mostly\(^\text{35}\) guarantees their revenues, such as the “revenue cap” change over time, hindering their full inclusion in the asset base. Moreover, some TSO remarked that in their regulatory regimes at least some costs were not necessarily recovered, so that some uncertainty remained.

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\(^{33}\) According to the ACER Recommendation, 23 for electricity and 24 for gas. See also the Position paper “Financing of Infrastructure Projects”, submitted by E-Control during the consultations for the present research.

\(^{34}\) P.3.

\(^{35}\) Particularly in the electricity sector. In the gas sector, there are exceptions where it is hard to have a guaranteed revenue for TSOs that are heavily exposed to transit flows, which entails a significant market risk due to inter fuel as well as some pipe to pipe competition (especially in the case of dedicated interconnectors). In such cases the NRA is usually reluctant to have shippers and end users bearing the risk of swings in the pipelines’ load factor.
or “cost plus” approaches, but allows only limited rates of return. As a consequence, their betas are usually well below unity, reflecting the very limited variability of their revenues: for this reason these companies are often described by finance experts as “defensive” stock against volatile markets, as they yield low returns but feature relatively low risk.

The beta factor can in principle be evaluated for each TSO, by considering its share price over a certain period. For TSOs that are not private or price listed, or whose shares have been on the market for relatively short periods, NRAs adopting the CAPM may estimate the beta using international peer group data and considering sample averages (or medians). In other cases, NRAs refer to average or median values simply because the aim is simply to estimate the beta of a whole sector and hence measure an average exposure to risk, rather than perform an analysis on specific projects.

Financial institutions like the European Investment Bank agree that the determination of beta is an appropriate approach to the assessment of the company risk. Yet, this approach draws some criticisms, too. In an interview, a TSO pointed out the possible downsides of a beta factor calculated on historical data and peer group data. Firstly it noticed that it is very difficult to identify a representative peer group due to the differences in TSOs across different countries. Secondly, inferring future financial results based from past share price history may result in biased conclusions as the context changes very rapidly. On the other hand, beta estimation based on recent years only may lead to overestimate the effect of one-off specific event (such as a financial crisis or other extreme events). Additionally, little meaningful information can be drawn from historical market data for new projects and products.

In few cases (5/30 for electricity and 3/29 for gas), NRAs do not use the CAPM but calculate rates of return (RoR) on assets (or equity) in different ways. Since such RoRs are normally higher than yields of long term government bonds (known as “risk free”), some risk factor is implicitly accepted and included in the RoR. For instance, in Spain the RoR is determined by law at 200 basis points above the “risk free” rate. In one case (Denmark) no RoR is allowed but only a small interest in line with the inflation rate, aimed at preserving the real value of the assets.

3.2 Reasons which support the inclusion of project risk evaluation in regulatory design

The complexity of developing a sound and solid risk assessment methodology can potentially lead to a standoff between NRAs, TSOs and other authorities. The likelihood that regulators and TSOs would have a different perception of the risk entailed by new investment is confirmed by this study (Chapter 2) and by the poll about the challenges of financing new investments, undertaken in the Roland Berger (2011) study.

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36 In a period of financial turmoil, with a general increase in volatility, the ratio between the variance of defensive stocks and that of riskier ones increases, hence the beta of defensive stocks like TSOs’ and other utilities decreases.

37 In that study NRAs, TSOs and financial institutions were asked to rate the main risk typologies. NRAs, TSOs and financial institutions all agreed to qualify permitting challenges as very serious. However, as the study concludes, “NRAs generally consider the challenges less significant than TSOs and financing institutions. This may partly reflect the fact that it is the NRAs' job, as stakeholders in the energy transmission industry, to ensure that financing and investment challenges do not arise in the first place. It may also indicate that NRAs are not as aware of challenges as TSOs and financing institutions. TSOs and financing institutions rate the challenges similarly.” (pp. 66-68). Regulatory risk is another aspect, or perhaps just another name of the perceived difference. There is a logical circularity in requiring regulators to reckon, or face, regulatory risk. In fact, what other stakeholders often call regulatory risk is related to a different perception of how and when costs will be covered by
If a sound and solid methodology for risk assessment is not agreed and consequently not included in the regulation design, this could jeopardize the implementation of article 13 of the TEN-E regulation, and therefore lead to the loss of net benefits arising from projects that have been sanctioned by a positive benefit-cost balance.

It is therefore important to see whether theoretical reasons justify the inclusion of specific project risk evaluation in regulation design.

**Is the holistic valuation of risk efficient?**

As noted in the previous section, the prevalent approach to transmission regulation is the one which sees it as a “single” service that must be given a single “price”.

Consequently, project (rather than company) risk is not factored into the design of the regulatory regime and, consequently a “single price approach” is envisaged for all types of projects, where the RoR considers the “price” of the company risk. However, this approach may be a source of inefficiency and welfare loss, particularly where PCIs are concerned.

In fact, when a transmission or storage service consists of different subservices with their own costs and benefits, a single price for the service would probably jeopardize the “marginal”, higher cost services, as many of those deriving from the implementation of PCIs are likely to be. The obvious solution to this inefficient equilibrium, without changing the regulator’s goals, is to allow him/her to set different “prices” for different services, allowing a “discriminatory behaviour”, where services of the PCI would be paid more.

To understand the problem, let us take a simple numerical example of a power transmission system with a capacity of 10,000 MW and an average cost (including a normal return) of 100 M€/year, or 10 €/kW/year. Thus, the (capacity based) tariff for this system would be 10 €/kW/year. Suppose now that a PCI is proposed, connecting this system to a neighbouring one, with a capacity of 500 MW and costs of 10 M€/year, or 20 €/kW/year, and expected benefits of 30 €/kW/year. The average system tariff of 10 €/kW/year would clearly not be enough to pay for the PCI, which would not be built, with a loss of welfare of (30-20=) 10 €/kW/year.

In this case, setting a specific “price” for the service offered by the PCI would prevent the welfare loss. This is the rationale behind the requirement of a preferential treatment for the PCI.

Two alternative solutions could be suggested. If a separate price for PCI services is not easily applied, as the PCI is part of a wider service from which it cannot be disentangled, or if separate pricing is not allowed for legal reasons, the regulator could still encourage the PCI development by paying a higher price for it, and socialize the costs in the general service price. In our numerical example, the total cost of the system would be 110 M€/year and the average tariff would increase to

NRAs, over the lifetime of the assets. This different perception leads to a probably permanent disagreement over the riskiness of projects.

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38 We are assuming that this is the cost allocated to the system of the country that is considered in the example. We do not consider what happens in the neighbouring one, which is not relevant for this reasoning.

39 There may be legal changes needed to achieve such treatments in several jurisdictions, where granting a different regulatory treatment to PCIs according to their risk profile, may be against the law. However, as mentioned in Chapter 4, the project team is not aware of any potential barriers to the implementation of regulatory incentives resulting from legislation in force (or planned) and the legal frameworks/structures of Member States.
(110 M€/10,500 MW) or nearly 10.5 €/kW/year. Since benefits would not accrue to all customers, the regulator may however be reluctant to choose this way.

Moreover, even if accepted in principle, this option would probably trigger a higher regulatory risk. In fact, the authority in charge of deciding the investment (which is not necessarily the NRA) would mandate the development of the PCI, under the promise that costs will be included into the asset base. However, a higher regulatory risk would be perceived in such a case and the promoter is likely in turn to be a reluctant agent to implement it (moral hazard). Considering that projects with special difficulties require adequate commitment to overcome challenges like local opposition, raising external finance or coping with less proven technologies, it is likely that several such projects would suffer delays, and a few may well be stalled. Therefore, this approach would require a clear and firm proposition for the acceptance of higher costs by the NRA.

Thus, the second solution to the problem illustrated by the above example is the use of a special regulatory treatment for more costly projects. In fact, there is a strong relationship between risks and costs: as already noticed, since to some extent a trade-off occurs between risk and cost. Often the development of projects can be smoother and less risky if the promoter is ready to spend more. For example, in the case of public opposition to facilities, higher costs may derive from rerouting, use of underground cables instead of overhead lines, or of sea-based rather than land-based gas pipelines; from public campaigns to better illustrate the project impacts; and other costly mitigation practices. In the case of less than mature technologies, risk could be reduced by resorting to higher quality – though dearer - materials, suppliers, and personnel. All such strategies may turn part of the risk into higher costs.

It is clear that if such higher costs are passed through to network users, higher risks are at least partly mitigated, and the justification for higher returns is reduced. Yet, this happens if the promoter is reassured that such higher costs are included into the asset base.

3.3 Towards a methodology for the project risk evaluation

As shown in section 3.1, almost no European NRA undertakes its own in-depth analysis of investment risk for projects, and only a minority (though growing number) require project promoters to present it. In this situation, several ways ahead can be considered for the implementation of article 13 of the TEN-E Regulation, taking into account also the deadlines that have been proposed. In fact, article 13.2 explicitly requires NRAs to analyse the higher risks incurred by PCIs, and to grant them the appropriate incentives in case a project promoter incurs risks higher than those normally incurred by a comparable infrastructure project. The Recommendation also addresses the issue of the common methodology for risk evaluation. Pursuant to article 13.6 by March 2014 (later postponed to August 2014) each NRA should have published its methodology and the criteria to evaluate investments in electricity and gas projects and the higher risks incurred by them.

It is beyond the scope of this project to outline the details of a common risk assessment methodology. However, since no current best practice could be found, we present stakeholders’ views on this and discuss the main solution lines that may be considered. Our recommendation on the best approach to a common methodology for risk evaluation is presented in chapter 5.

According to the views expressed by stakeholders, a case by case methodology is favoured, as the projects are potentially very different from one another. Some NRAs

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40 This is often referred to as command and control approach.
are not willing to develop and use a separate methodology applicable to PCIs only. On the other hand, it seems reasonable that the methodological framework should be the same for all, as is the case of CBA.

In the Recommendation ACER proposes a step-wise approach for a common methodology for risk evaluation. First of all, ACER argues that the methodology should consider the distinctive features of different national regulatory regimes, and it should be transparent. ACER recommends the following 7 steps:

- **Step 1.** Project promoter provides all the necessary information for the proper assessment of the actual risk exposure.
- **Step 2.** Concerned NRAs identify the project risk, sorting them into the following categories:
  - Risk of cost overruns
  - Risk of time overruns
  - Risk of stranded assets
  - Risk related to the identification of efficiently-incurred costs
  - Liquidity risk
- **Step 3.** Concerned NRAs assess any risk mitigation measures that can be undertaken by the project promoter.
- **Step 4.** Concerned NRAs assess to what extent the project risks are already compensated/remunerated for in the allowed cost of capital, determined according to the CAPM approach.
- **Step 5.** Concerned NRAs assess any risk mitigation measures that are already in place in the applicable regulatory framework.
- **Step 6.** Concerned NRAs quantify the risk as far as possible.
- **Step 7.** Concerned NRAs assess to what extent the risk for the project promoter is higher than the risk of a comparable project and to what extent this is justifiable when compared to a lower risk alternative. Identification of the comparable project should be carried out on a case-by-case basis and in general the comparison should be between projects located in the same country, although exceptions are possible.

In what follows we discuss the main solution lines that may be considered, namely:

- Implicit risk assessment through market based incentives for the project;
- Embed the risk assessment in the project’s cost benefit analysis;
- Define all the aspects of an explicit risk evaluation methodology to be applied to each specific project (i.e. clearly set how to rate any project risks for any project); and
- Define a common procedure illustrating the main highly recommendable steps to follow when evaluating project risks (and leave more degrees of freedom as far as the risk quantification is concerned).

These lines are not mutually exclusive but are parts of the solution and could be combined in the most suitable ways. Our recommendation on the best approach to a common methodology for risk evaluation is presented in chapter 5.

**Implicit risk assessment through market-based incentives**

If no explicit risk evaluation is feasible, the choice could in principle be left to the market: the project would be (at least partly) remunerated by market-based benefits.

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...we did not find evidence suggesting that project-type specificity requires significantly different CBA methods. The Regional Groups should be aware that all project types can and should be evaluated with the same CBA method." (Policy Brief FSR, p. 5-6. Received from: [http://fsr.eui.eu/Publications/POLICYbrief/Energy/2014/PB201403.aspx](http://fsr.eui.eu/Publications/POLICYbrief/Energy/2014/PB201403.aspx).
rather than by regulated tariffs. In some cases, if higher risks are detected but a substantial part of the benefits can be appropriated by market players and their customers, NRAs could devise mechanisms to leave promoters at least part of such benefits.

Excluding the case where exemptions from TPA are provided, which is explicitly ruled out from the provisions of article 13 of the Regulation, the plausible cases are mostly where cheaper energy sources can be connected, e.g. external sources of gas and electricity which can be sold on the market at a profit. These cases are probably mostly electricity interconnectors between markets with structural costs differences, so that charges for use of the interconnection can be attained or congestion rents can be extracted. Mixed regulatory schemes could be suggested, like “cap and floor” mechanisms that grant minimum cost coverage to the promoters but leave them, as an incentive, the possibility of extracting some value from sales of the facility services.

This approach does not as such prevent NRAs from analysing the risks, as they must in any case sanction their existence so that the scheme can be applied. However, since the incentives are provided by the market, the analysis need not be quantitative, and is therefore in principle less demanding. In other words, the NRA would declare that higher risks do exist, after having ascertained the existence of one or more conditions, and as a consequence allow the project promoter to access the scheme.

This option was chosen in the case of the NEMO project, a proposed power interconnector between Belgium and the United Kingdom. However, this solution has been proposed for electricity interconnectors only and may not be easily replicated. In fact, the more integrated the market, the less exploitable rents are probably left for the promoter. Hence, this is likely to be a suitable solution for the “first movers”, but it is not sure whether such benefits (which depend on price differentials) will last. Furthermore, it may not be as suitable for gas interconnectors, where congestion rents are perceived as lower and gas interconnectors suffer more from inter-fuel competition as well as from that of other gas transmission routes. Additionally, this approach may not work for infrastructures that are built for security of supply reasons.

Embed the risk analysis in the cost benefit analysis

This approach would rely on the existing CBA, which is required for PCIs anyway. Methodologies already exist for such a CBA, and it is likely that the original design of the CBA would in most cases already consider risks and uncertainties of the projects, even though the final decision is based on expected values.42

In fact, a CBA typically assumes a probability distribution for both costs and benefits: the shape of these distributions and the value chosen within the distribution (such as the expected value) is an implicit assessment of risk.43 CBA methodology so far pays only limited attention to risk sensitivities (as this was not required and risk

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42 ENTSO-E, Guideline for Cost Benefit Analysis of Grid Development Projects, November 2014, p. 43. Note that regarding costs, in its recommendation of 25 September 2013 on cross-border cost allocation (Annex I electricity CBA and Annex II gas CBA) ACER recommended that an uncertainty range (-x%; +y%) with respect to the expected costs and benefits in each country is presented. A narrative description of reasons underlying the possible variations has to accompany the uncertainty range.

43 The main difference with the previous approach lies in the fact that in that case benefits are directly attained by project promoters by selling products and services to the market, whereas in this case they are awarded by the regulator in relation to delivery of predetermined outputs. See Frontier & Consentec (2008) for further discussion.
assessment and CBA have been conceived as different exercises), but these may be added in the next update of the methodology.

This approach would be consistent with article 13.2 of the TEN-E Regulation, which requires that “The decision of the national regulatory authorities for granting the incentives referred to in paragraph 1 shall consider the results of the cost-benefit analysis [...].”

Moreover, this approach would avoid “inconsistent” behaviour by project promoters, who might present the project very differently when discussing the CBA with Regional Groups, and when arguing for special treatment based on high risk in front of the NRA. In the former case, they are interested in downplaying risk to see the project accepted, whereas in the latter they would have an interest in asking for higher returns to offset higher risk.

As in the previous approach (where higher risk were remunerated by the market), the first burden of risk evaluation would fall on the promoters rather than on NRAs. At the same time, there would be a reduced incentive for promoters to misrepresent benefits, as they would actually be remunerated only in relation to the actual delivered “products” to which the benefits are associated (in the above examples, only in relation to the connected new energy sources that were actually delivered).

On the other hand, a few difficulties can be detected in this approach. First, CBA has been devised mostly to address social and environmental issues, as well as the correct distribution of benefits and costs among jurisdictions. Substantial inclusion of a risk dimension may overburden the methodology. That said, synergies can be found with the sensitivity analysis of the CBA, which can include some risk elements: CBA sensitivities may be a starting point. The cost analysis of the CBA may be a component of the risk assessment exercise, also because CBA and assumptions made in the risk assessment should be consistent.

Second, remuneration of benefits in relation to output indicators may be beyond the control of project promoters. For example, congestion of an interconnector or usage of a sea-line connecting an offshore wind farm is typically related to market events that are beyond control of TSOs. Yet, this could be the basis for awarding a regulatory treatment in line with those of suppliers (exposed to output market risk) rather than transmission operators.

Explicit evaluation of risk

In principle, a methodology to explicitly assess risk should have the following features:

44 “Each cost-benefit analysis shall include sensitivity analyses concerning the input data set, the commissioning date of different projects in the same area of analysis and other relevant parameters ...”. The point is also underlined in “Cost Benefit Analysis in the Context of the Energy Infrastructure Package, THINK Report, 2013”, p. 22, which recommends quantitative uncertainty modelling of scenarios as a combination sensitivity analysis, definition of ranges of sensible variables, and stochastic modelling the calculate the distribution of net project benefits. This Report also supports ENTSO-E’s original proposal to use ranges for infrastructure costs rather than single values, which was however dismissed in the CBA’s latest version. The same source also notices that “The benefits of some project might be more uncertain than those of other projects. The Regional Groups need information on the robustness of the benefits. This information can be provided by means of a sensitivity analysis to the major determinants of the costs and benefits. It is also important that the outcome of such sensitivity analysis is reported in a clear and informative way.” (Policy Brief FSR, p. 5-6, http://fsr.eui.eu/Publications/POLICYbrief/Energy/2014/PB201403.aspx).
- **Objectivity.** The assessment should be based on evidence; in most cases, a transparent approach to valuation is the most objective possibility. Third party validation may be considered by envisaging the involvement of at least some expert or lay observers, who do not have interest in the project.
- **Simplicity.** Too complex methodologies may not be helpful.
- **Transparency.**
- **Consistency with investors’ perspective.** Financial institutions usually evaluate project risk by modelling future revenues and costs related to the single asset. They:
  - Tend to focus on the single project or its related assets, not on the whole project promoter’s revenues;
  - Test the impact of possible negative scenarios (such as cost overrun, delay in construction, inflation evolution, regulatory changes) by performing sensitivity analysis, where they assess whether the rate of return remains acceptable for them;
  - Explore the actual support to the investment to shed light on the time needed to get to the final investment decision;
  - Do not attach a single number/probability to each risk, but qualitative approaches prevail. Interviewed investors reckon that they do not have a specific risk assessment methodology for PCIs, and note that only in few cases data allow the definition of probabilities.
- **Consideration of whether the risk is neutralised/mitigated for the project promoter by the regulatory framework.** The assessment should take into account whether risks are born by project promoters or by consumers, which depend on the regulatory framework. Risk exposures are therefore expected to vary between countries. This analysis should include in particular:
  - How the NRA proceeds in the assessment of incurred costs (e.g. by using benchmarking or standard costs);
  - The scope of costs that are included, including for example costs incurred abroad, communication campaigns, and other costs that are not typical of usual projects;
  - The time for which the cost base is guaranteed, which may go beyond the usual regulatory period;
  - The availability of higher rates of return.
- **Exclusion of risks specific to the project promoter, such as complexity of management, as well as risks for which standard insurance and hedging instruments exist.** These should be excluded from the scope of risks to be considered for incentives.

In principle, the assessment of the risk level may be quantitative or qualitative. The quantitative approach may be too complex and end up being not very objective or transparent. Moreover, lack of data hampers a quantitative valuation of several typical risks that are often underlined for PCIs, like those of permitting of relatively new technologies. On the other hand, a qualitative approach that eventually leads to quantitative incentives is just as subjective. A simple qualitative method is the matrix of risks, which qualitatively evaluates the likelihood and impact of each type of risks (see Box 1 below).
The methodology could be based on expert panels (as in the Delphi method\textsuperscript{45}), who would be asked to rate risks from a large list, as provided in chapter 2 of this report. Experts could be drawn from a rather large sample, including academics and others who are not stakeholders of the projects. The principle is to split risks into its analytical components, so that the expert judgment is as little influenced as possible by the experts’ opinion on the projects to which they apply\textsuperscript{46}. Nevertheless, some quantitative indicators may be suggested wherever possible for each risk component: for instance, the number of involved TSOs/NRAs may be used to assess the coordination risk.

A more detailed illustration, for illustrative purpose, is provided in Box 1.

**Box 1: Methodologies for direct risk evaluation**

| An explicit risk evaluation may involve the following steps: |
| (1) The first step is to identify a number of PCI projects which already exist and are operating. Characteristics of those projects are described, in terms of the various traits that we have identified in the PCI typology outlined in section 2.2. For example, a PCI could be identified as being cross-border, using proven technology and it is a new project. |
| (2) Based on any available reports, data and own analyses, those projects should then be subjected to a risk analysis exercise by the most appropriate entity, whom should be objective/neutral. Each of the risk types that we have identified should be considered, and each risk can be individually assessed for the PCI. The risk assessment would be considered on the basis of risk likelihood and impact. Some systematic (standardized) means of analysing risks should be crafted. If no objective probability can be defined, an expert panel could be asked to provide their value in a Delphi exercise. The composition of the panel for the Delphi exercise should be agreed by stakeholders, possibly through a consultation process. A similar ENTSO-E exercise was run for the 2012 TYNDP projects and could represent an interesting example, but in this case the assessment of risks cannot be left to TSOs only. |
| (3) For each existing PCI, following the analysis of each risk factor, a summary of the risk profile is made. |

A variant of this approach could consist of evaluating the role of projects (or of their features, in terms of elementary causes) for each company of a sample. The impact of these features on accepted risk measures (like the “beta”) could then be estimated by statistical analysis. The analysis would evaluate and estimate the exposure of such companies to the main risk factors, for example their operation in densely populated or environmentally sensitive areas, the resort to less proven technologies, the exposure to cross border trade etc. The study would be based on more objective parameters, but it would not be easy and could be time consuming. Furthermore, since investments are often decided by suppliers for portfolio optimization rather than for the projects’ individual merits, even the objectivity of such analysis may be questioned.

\textsuperscript{45} The Delphi method is a multi-round procedure for forecasting (or more generally, assessing unknown values), based on the interaction of an anonymous group of experts, who interact with the help of a facilitator. It is widely used in business forecasting, as well as in other sectors.

\textsuperscript{46} This approach is akin to what is used in CBA to assess the robustness of results: “Benefits are defined by a tabulated scoring system completed by processional power engineering judgement rather than by algorithmic calculation” (ENTSO-E, Guideline for Cost Benefit Analysis of Grid Development Projects, November 2014, p. 41.)
A further source of information could come from the mergers and acquisition processes. In case of acquisition of other companies which embody a certain risk, due diligence evaluators on behalf of buyers use discount rates that represent a valuation of the inherent risk the purchased company faces. This valuation is not necessarily the same as the general sector risk, but would provide hints at the risk valuation as seen from the financial community.

Another approach amounts to assuming that some types of PCI are intrinsically more risky than others. This would be a partial departure from the “case by case” logic. The typology illustrated in chapter 2 may be used for this purpose. For instance new projects are generally considered more risky than expansion, off-shore platforms/DC cables are perceived as more risky as they are new technologies. According to Roland Berger (2011), interconnector projects involve higher risk and the same is often true for offshore grid connections and potentially also for gas security of supply projects. According to Frontier & Consentec (2008), cross-border projects are more risky. Regarding gas, PCIs facing higher risks may include those related to increased security of supply (e.g. gas reverse flows) and challenges have also been mentioned for gas projects where the commitment horizon of shippers may be relatively short compared to the depreciation periods used.

A different source of risk assessment is the analyses prepared by promoters, which may include evaluations of the probabilities of adverse events. However this risk assessment is only useful if prepared before the methodology itself is available, and particularly before incentives are provided; otherwise they might be biased in order to increase the project riskiness and the ensuing rewards. Estimates of benefit and cost ranges are typically provided in such analyses, and may be used to assess their uncertainty: these could be the source of meta-analysis aimed at quantifying the typical risk that are related to objective parameters, like technology, cross-border coordination and others47.

In any case, the development of an explicit risk assessment methodology is no easy task, notably if it is the basis for the definition of incentives.

Some challenges should be taken into account when addressing this option. Here we mention them:

- The concept of a "comparable project" used in article 13 of TEN-E Regulation is difficult to translate in practice.

- Given the limited expertise and resources in direct risk evaluation by NRAs, the scope of the ACER recommendations pursuant to article 13.5 of the TEN-E Regulation would have to be broadened in practice. It would be preferable if a risk analysis exercise were run at a centralized EU level, much in the same way as a CBA methodology has been prepared by ENTSOs rather than individual TSOs. For example, ACER could collect a larger information and expertise mass than individual NRAs, including by collecting the currently existing expertise available among NRAs as well as TSOs and the financial community.

- Results of an expert judgment, including by experts who are not local and do not belong to involved stakeholders or NRAs, can only be seen as preliminary. Actual risks of the projects can only be defined on a local basis, after due consideration

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47 A typical problem with CBA lies in the fact that its outcome may be biased by the availability of EU grants. A country may find it worth to overstate its benefits, even if this leads to bearing higher costs, if this is outweighed by the opportunity to obtain an EU grant.
of the specific case and of the existing regulatory framework. The methodology would face similar difficulties, similar to those found in the CBA process for the definition of some externality value."48

3.4 Concluding remarks

The definition of a direct valuation of risk as a basis for incentives is no easy task, nor can it be the outcome of consolidated, science-based methodologies. It is rather an exercise that is influenced by the perception of risks by project promoters as well as their production factor providers, notably financial institutions. Therefore, any general definition of risk and any approach to its valuation as a basis for the provision of an enhanced regulatory treatment should be addressed with great care, as it can only play a limited role in incentive provision.

Such risk evaluation can be better performed by project promoters and financiers, who have the best resources and expertise to implement it. However, if they know that risk evaluation can lead to incentives, there is clear scope for strategic behaviour. The risk is clearly to increase costs by providing incentives that are not needed, and/or to include in tariffs both higher costs incurred to mitigate risks and the higher return required to address them. Therefore, the reliability of project promoters’ analysis is greater, the farther they are from incentive provision. Yet, a few past cases could provide useful guidance.

As for the choice of an approach to risk evaluation, the limited availability of objective criteria suggests that the transparency of evaluation procedures could matter even more than the technical methodology itself. It is certainly wise always to verify if objective parameters do exist: if that is the case these can be the basis of “output based regulation”, where part of the benefits arising from projects are left to their promoters: in this way risk evaluation and incentive definition are merged, reducing the evaluation burden of regulators and of other government agencies. Yet, only some projects are suitable for this approach. It should be stressed that output-based incentives are alternative to input-based ones, rather than added on top of traditional regulation.

In a few cases, it is also possible to attach parts of the incentives to output indicators rather than to risk. Examples are the achievement of security of supply parameters, the reduction of price differences between adjacent markets, the increased connection of renewable or other preferred sources of electricity and gas etc.. In these cases, the evaluation of social, environmental and other common benefits – which is already a task undertaken at EU level as a consequence of the TEN-E regulation – could be undertaken, and incentives could be based on them.

Yet in other cases, no such approach may be feasible, because special risks of some projects are not necessarily linked to any quantified benefit. In these cases, risk assessment is necessary. Whilst some methodologies do exist for such an evaluation, as noticed in the previous section and in several comments to a previous version of this Report, their rather subjective nature entails that their use should be characterised by the greatest transparency. The way to ensure this goal will be taken up in more detail in Chapter 5.

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48 The Value of Lost Load, which could not be determined at EU level, is a suitable example of the likely difficulties.
Chapter 4 – The use of regulatory incentives
4. USE OF REGULATORY INCENTIVES

In this study, regulatory incentives are defined as mechanisms incorporated in the regulation that facilitate or stimulate investments.\(^{49}\) The purpose of such mechanisms is to influence the risk-reward ratio resulting from the regulation. In general, such mechanisms can facilitate or stimulate investments in two ways, namely by mitigating risks for project promoters and/or by increasing rewards for project promoters. To understand the optimal way of motivating project developers to realise investments, consideration should be given to the types of mechanisms which effectively and efficiently address certain risks (as shown in Figure 5).

**Figure 5: the use of incentive mechanisms to address unacceptable risks for a PCI**

Examples of regulatory incentives that can be granted in the case that a PCI has a higher (and, for the project promoter, unacceptable) risk profile than comparable projects are specified in article 13 of the TEN-E Regulation. It is explained that they can include:

- The rules relating to anticipatory investments;
- The rules for the recognition of efficiently incurred costs before the commissioning of the project;
- The rules for providing additional return on the capital invested in the project; and

\(^{49}\) In this context, reference is made not only to discrete incentive mechanisms used to overcome specific identified risks during the investment cycle. NRAs make use of a broad spectrum of measures to support investments. The regulator’s investment measures define the overall framework governing investments in the sector. The use of specific incentive mechanisms forms just one part of the regulator’s overall provision of investment measures.
PCI risk profiles vary depending on the specific type of a project. Hence, the optimal selection of incentives and measures which NRAs could implement to support timely developments may also be specific to the type of PCI. That is, the optimal incentives which regulatory authorities could adopt may change depending on the type of PCI being supported. This aligns with ACER’s recommendation that ‘the NRAs’ decision on granting incentives should involve the selection of the best-suited risk-handling tool(s) – e.g. monetary schemes or risk-mitigation regulatory measures – in order to promote the timely implementation of PCIs. It should consider the results of a cost-benefit analysis and in particular the regional or Union-wide positive externalities generated by the project. Incentives should be commensurate with the level of risk faced by the project promoters.’\textsuperscript{50}

This does not, however, imply that a regulatory incentive cannot apply to several or all types of PCIs. For instance, using regulatory accounts for the mitigation of volume risk seems to be adequate, independent of the specific type of PCI under consideration.

In the following sections, we first take an inventory of regulatory incentives, explaining the means by which each incentive functions. Following this, we identify which regulatory incentives have potential to address specific risks related to investments. Next, a detailed description of the uses and applications of regulatory incentives in various EU countries is provided, including information concerning the procedural method for deciding whether to grant an incentive and the different actors involved in the process. Examples of best practice in the use of regulatory incentives are described. Lastly, stakeholders’ views\textsuperscript{51} on the optimal use of regulatory incentives are considered, highlighting in particular which incentives both NRAs and TSOs view as being most (and least) effective in addressing risks.

### 4.1 Inventory of incentives

An introduction to the key incentive mechanisms which may be used in the regulation to incentivize investments in infrastructure is set out below. The regulatory incentives can be broadly grouped into two categories: rewarders and mitigators. Rewarders are the incentives that increase profit or shorten the cost recovery period of a project promoter; these are defined in Table 1. Mitigators reduce or eliminate the risk for a project promoter by shifting the risk to the users of the infrastructure; these are defined in Table 2.

<table>
<thead>
<tr>
<th>Regulatory Incentive</th>
<th>Means of addressing risk</th>
</tr>
</thead>
<tbody>
<tr>
<td>Premiums (WACC surcharge)</td>
<td>The key instrument providing incentives to project promoters to invest in infrastructure is the allowed rate (or amount) of return that a company is entitled to. Essentially, the rate of return is equivalent to the level of profit a company can expect to obtain on its regulatory asset base.</td>
</tr>
<tr>
<td></td>
<td>Regulators can encourage investments in infrastructure by including a premium within the</td>
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</table>

\textsuperscript{50} ACER, 2014. Recommendation on incentives for projects of common interest and on a common methodology for risk evaluation. Recommendation No 03/2014

\textsuperscript{51} Received in the course of this project from stakeholders through the questionnaires, interviews and workshops
| Rules for anticipatory investments<sup>52</sup> | NRAs may establish - and communicate to project promoters - well-reasoned rules relating to anticipatory investments in infrastructure which will be needed in order to prevent inadequate and untimely infrastructure developments. Well-considered anticipatory investments also help to keep various future infrastructure development options open and feasible. However, it is unaffordable and unrealistic to try to keep all options on the table for an indefinite period of time. Hence, the use of clear and well-considered rules for anticipatory investments can help to ensure that companies understand which types of investments to undertake. |
| Adjusted depreciation periods | Given that depreciation can account for a significant proportion of a regulated company’s total costs, such companies will be more motivated to make investments in infrastructure when they enjoy greater certainty that their depreciation costs will be recovered (and conversely, will be less motivated to make investments when there is less certainty that their depreciation costs would be recovered). A key aspect of ensuring that companies are incentivised to make investments is to ensure that the pattern of recovery and the period over which the invested capital is returned to the company are favourable. |
| Exemption from efficiency gain requirements | A NRA may opt to allow some companies to enjoy exemptions from requirements to achieve performance and cost efficiency improvements, during a given regulatory period. The effect of this measure is to incentivise companies to undertake investments because there will be less (or no) risk of not achieving efficiency improvement levels (which would mean that companies would be punished financially by the regulator). Such an incentive measure can help |

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<sup>52</sup> Anticipatory Investments are investments in assets that may need to be made before demand for the assets' services exists, for example constructing a pipeline of a certain maximum capacity before reaching the expected production level from a gas field. There is a risk of “stranded assets” if investments are made in assets which are not used because the demand for their services does not develop as expected.
regulated companies to focus their strategic operations on investing in infrastructure, as they are less constrained by the need to shape their strategic operations to meet efficiency improvement requirements.

| Sliding scale | This mechanism sets incentives for regulated companies to achieve specific regulatory targets by splitting the benefits or costs of over- and under-achieving those targets between the company and the customers (following pre-set rules). This approach is also known as profit sharing. Using this system, the regulator establishes a target level for specific items (e.g. investment costs, OPEX reductions, etc.) and if the regulated company can fulfill the target (within a pre-defined range) the benefits or costs are recognised to their extent by the regulator. If actual costs are outside of the pre-defined range, the benefits or costs are shared between the company and its customers. Sliding scale mechanisms are advantageous because they can help to address issues related to the informational advantage of the regulated company over the regulator. Specifically, sliding scale mechanisms encourage the company to submit realistic investment forecasts to the regulator because the mechanism would eventually punish the company for any inaccuracies between actual and predicted (forecasted) costs. Without the use of such a mechanism a regulated company might be tempted to submit investment forecasts to the regulator which overestimate its costs, and the regulator might have difficulties in knowing/proving any inaccuracies in such forecasts. |
| Favourable debt/equity ratio in the WACC | In setting tariffs and calculating the WACC for regulated companies, a NRA often makes an assumption related to the debt equity ratio of companies’ investments. This value of the ratio is normally assumed as being a typical average which would be in effect across all the industry’s regulated companies. The debt equity ratio which is used has a direct impact on the size of the WACC value. In general, for large infrastructure projects, companies seek to gear projects with as much debt finance as possible because the interest rates that they pay on debt finance is typically lower than the costs of equity finance. In calculating the WACC, and hence the rates of return (financial profits) that companies are entitled to receive in return for their costs of investment, regulators’ selection of the debt equity ratio impacts directly on companies’ future financial returns. Therefore, one incentive which regulators can implement in order to encourage investments in infrastructure is to fix a debt equity ratio which will entitle companies to receive attractive rates of return. |
Table 2: Mitigators

<table>
<thead>
<tr>
<th>Regulatory Incentive</th>
<th>Means of addressing risk</th>
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<tbody>
<tr>
<td>Cost plus regulation</td>
<td>The cost plus method allows a project promoter to be certain that its costs will be recovered fully, and also ensures that a certain level of profit is guaranteed. The level of the cost plus can be adjusted within the regulatory approach in order to ensure that excessive gains are recouped by the regulator and also to compensate a project promoter for any excess losses it suffers. One advantage of this incentive is that very little information is required per se in order to use the incentive mechanism, and allows the project promoter to know in advance and with certainty what level of return it can expect on a particular investment.</td>
</tr>
<tr>
<td>Longer regulatory periods</td>
<td>The use of longer regulatory periods is sometimes justified on the assumption that longer regulatory periods provide stronger incentives for regulated companies to achieve cost reductions. Longer term price controls tend to be less risky when the market is more stable (when there is limited demand volatility) and when the market is characterised as having lower levels of exogenous risks. The use of longer regulatory periods can allow companies to internalise the costs and benefits of their investments within a single (or at least fewer) price control period(s). This can help to incentive companies to realise efficiency improvements and innovation advancements. Longer regulatory periods also provide regulated companies with certainty over the regulatory conditions which will be in effect, and over a longer period of time. This has the effect of reducing companies’ concerns that regulatory conditions may change in the very near-term future. If a company is concerned that regulatory conditions will change in a way which is detrimental to their position, and in the relatively near-term future, they may be more reluctant to make investments than in a situation of having longer-term certainty on regulatory conditions. On the other hand, longer regulatory periods may magnify problems that arise if (for instance) a positive or negative discrepancy between revenues and costs arise, possibly for reasons beyond control of the companies. In particular, demand is less stable in gas markets than in electricity. Thus, it may be preferable to only use longer regulatory periods for projects which have the highest risk profiles.</td>
</tr>
<tr>
<td>Stability arrangements</td>
<td>Regulatory arrangements are often required to be re-shaped due to changes in policy frameworks and legislation, over which they have no control and are...</td>
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</table>

on their investments.
duty-bound to follow. However, various tools are employed by regulatory authorities to provide companies with some guarantee of regulatory stability, including:

- Using fixed regulatory terms, where the regulator guarantees not to adjust certain key factors during a specific period of time;

- Regulators may also strive to ensure that they give notice to companies if and when they are considering options for changing regulation;\(^\text{53}\)

- Regulators can also consult with regulated companies to get their inputs on how changes could be designed and implemented in a way that reduces any costs of adjustments and may reshape desired outcomes to fit better with companies’ capabilities;

- Regulators can also implement any changes in stages to ensure smooth transitions and a framework which is as stable as possible;

- Regulators can give companies some flexibility in complying with any regulatory adjustments and the means with which they achieve compliances; and

- Regulators may provide a large amount of information, advice and support to companies regarding regulatory changes and potential future developments. This results in companies having a solid understanding of what and why the regulator is aiming at achieving through any regulatory developments.

### Exemptions from regulation

This can act as an incentive to investment by removing specific obligations and requirements on project developers, which may have impact on the project’s attractiveness. For example, projects may be granted special exemption from the requirement to provide third party access to other market players in the use of an asset being developed, which could help to alleviate concerns related to asset use availability (and revenues). Project promoters might also secure a waiver from the requirement (or an extension to the agreed timetable) for the unbundling of their business activities if it is determined that such an exemption measure is important for the viability of the proposed project.

### Early recognition of costs

Construction work in progress (CWIP) is the term used to describe the money that has been spent, at a given

\(^{53}\) Centre on Regulation in Europe, Regulatory stability and the challenges of re-regulating, 2013. Received from: http://www.cerre.eu/sites/default/files/130204_CERRE_Study_Stability_Final.pdf
point in time, on an infrastructure asset that, at that time, had still not been commissioned. Due to very large scale of infrastructure investments (and significant construction periods), some NRAs allow specific arrangements for CWIP. Regulatory arrangements for this issue could take a few forms, including:

- The regulator may allow the capitalisation of both the debt and equity costs incurred by the regulated company during the construction period;
- A regulator might allow the inclusion of the cost of capital (that is, the allowed return on debt and equity) but does not include the depreciation in the allowed revenue during the infrastructure construction period; or
- A regulator could also decide to partially include CWIP within the regulatory asset base. This could be a favourable option for projects with a relatively short construction period.

### 4.2 Matching incentives to risks

In the tables below, the risks that have been identified as potentially relevant in case of a PCI have been presented in the column on the left. Then the matching incentives (mitigators and rewarders) have been suggested. This matching table is a simplified presentation of advanced selection of adequate incentive measures addressing well-defined risks that a given regulation is aiming to mitigate or compensate for.
<table>
<thead>
<tr>
<th>Policy and Legal</th>
<th>Mitigators</th>
<th>Rewarders</th>
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<tbody>
<tr>
<td>Changes in policy</td>
<td>Longer regulatory periods ○ Stability arrangements ○ Exemptions from regulation ○ Early recognition of costs ○ Premiums (WACC surcharge) ○ Rules for anticipatory investment ○ Adjusted depreciation periods ○ Exemption from efficiency gain requirements ○ Sliding scale ○ Favourable debt/equity ratio in the WACC ○ Cost recovery through cost plus regulation</td>
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<tr>
<td>Lack of proactive political support</td>
<td>○</td>
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<tr>
<td>Gaps, grey areas or poorly-defined laws</td>
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<td>Bottleneck at the stage of public consultations</td>
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<td>Lack of sufficient cost recovery mechanisms ○</td>
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<tr>
<td>Potential and/or actual legal barriers preventing investors from buying shares in PCIs</td>
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<td>EU funding decreasing the project ROE as funding/grant amount not included in the RAB</td>
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Finance and capital markets

Higher interest rates due to long project lifetime and financing period
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Difficulties in ensuring adequate debt financing sources
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<td>Favourable debt/equity ratio in the WACC</td>
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| Controversial cross-border cost allocation  |            |           |

| Counterparty risks                          |            |           |

| Asymmetry of resources and/or interests of stakeholders |            |           |

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<th>Energy markets</th>
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<th>Rewarders</th>
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<td>Competition with other projects, including PCIs</td>
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<p>| Changes in energy markets (e.g. fuel prices, market design, CO2 allowances) |            |           |</p>
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<td>Longer regulatory periods</td>
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<tr>
<td>Uncertain demand forecast due to uncoordinated generation and transmission investment</td>
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<td>Non-harmonised market arrangements between countries</td>
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<td>Biased decision-making process due to bundled interests in generation and transmission assets</td>
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<td>Equipment failure</td>
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<td>Technology</td>
<td></td>
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<td>Lack of recovery mechanisms for OPEX caused by innovative/unconventional technology/setting</td>
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<td>Lower CAPEX recovery if asset lifetimes are shorter than expected</td>
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<td>Non-available or difficult access to technology</td>
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<td>---------------------------------------------------------------------------</td>
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<tr>
<td>Longer regulatory periods</td>
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<tr>
<td>Supply chain bottlenecks due to size of PCI and simultaneous delivery of regular investments</td>
<td></td>
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<td>High costs of searching and importing labour force from abroad</td>
<td></td>
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<td>Extreme environmental conditions disrupting construction operations</td>
<td></td>
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<td>Non-existing or non-available suitable labour force</td>
<td></td>
</tr>
<tr>
<td>Rise of labour force unit costs as a result of increased demand and squeezed supply</td>
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</tbody>
</table>
### Mitigators
- Longer regulatory periods
- Stability arrangements
- Exemptions from regulation
- Early recognition of costs
- Premiums (WACC surcharge)
- Rules for anticipatory investment
- Shortened depreciation periods
- Exemption from efficiency gain requirements
- Sliding scale
- Favourable debt/equity ratio in the WACC

### Rewarders
- Cost recovery through cost plus regulation

| Non-availability of sufficient quantity of the necessary materials for the development of PCIs
| Rise of the unit costs of materials due to relatively high demand and squeezed supply
|"
4.3 Regulatory incentives currently in use in EU Member States

In this section, an overview of the different regulatory incentives in application for natural gas transmission infrastructure investments in each EU Member State is provided (in Table 3). For each country, a description of the incentive is provided, as well as an explanation of the procedural means used to decide whether to grant the incentive or not to an investment, and the actor(s) involved in that decision-making process. Following the country overview, a more in-depth analysis of the use of regulatory incentives is provided for the particular cases of Belgium, France, the Netherlands, Estonia, the United Kingdom, Italy and Spain. The information presented in Table 3 relates to natural gas infrastructure only; the information presented in the remaining part of this section deals with investments in both electricity and natural gas infrastructure.

Whilst it is outside the scope of this assignment to analyse the legal frameworks of each Member State regarding potential use of different regulatory approaches, the project team has made various efforts to understand whether the legal frameworks and legislation of Member States create any potential barriers or obstacles to the future use of regulatory incentives. Specifically, the issue of the existence of potential legal barriers to the use of regulatory incentives was discussed at the second project workshop; all stakeholders were also invited to provide the project team with any relevant information or comments on this topic following the project workshop, and the issue was also considered during stakeholder interviews. In conclusion, the project team is not aware of any potential barriers to the implementation of regulatory incentives resulting from legislation in force (or planned) and the legal frameworks/structures of Member States.

Table 3: Summary of current incentive schemes

<table>
<thead>
<tr>
<th>Member State</th>
<th>Summary of current incentives in effect for normal infrastructure investments in natural gas sectors</th>
<th>Decision-making process on granting incentives</th>
<th>Involved actors (and their roles)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Austria</td>
<td>In Austria investment incentives are available for natural gas investments, in particular, incentives to allow efficiently-incurred investment pre-financing (construction) costs to be included in the RAB and reimbursed at an early stage in the project cycle. An investment premium is also available for project promoters to offset the volume risk of projects. CAPEX (which includes depreciation) is considered ex-ante on the basis of planned CAPEX values and according to the network development plan. Any appropriate CAPEX associated with the realisation of measures included in the network development plan, including cost of capital for preliminary financing of the project investment, is allowed when setting the system charges (that is, considered and included in the RAB). The NRA and the TSO.</td>
<td>CAPEX (which includes depreciation) is considered ex-ante on the basis of planned CAPEX values and according to the network development plan. Any appropriate CAPEX associated with the realisation of measures included in the network development plan, including cost of capital for preliminary financing of the project investment, is allowed when setting the system charges (that is, considered and included in the RAB).</td>
<td>NRA and the TSO.</td>
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<tr>
<td>Austrian method takes the capacity investments planned for the regulatory period (i.e. ex-ante consideration of investment projects) into account. At the end of the regulatory period, the regulator checks for deviations between planned investments and the appropriate investments that were made. Any deviations in capital costs are revised and taken into consideration when calculating the costs in the following regulatory period.</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Belgium</td>
<td>No specific investment incentives</td>
<td>N.A.</td>
<td>N.A.</td>
</tr>
<tr>
<td>Croatia</td>
<td>In the gas distribution segment, a ‘Regulatory Account’ incentive is in place.</td>
<td>N.A.</td>
<td>N.A.</td>
</tr>
<tr>
<td>Czech Republic</td>
<td>No specific investment incentives</td>
<td>N.A.</td>
<td>N.A.</td>
</tr>
<tr>
<td>Denmark</td>
<td>No specific investment incentives</td>
<td>N.A.</td>
<td>N.A.</td>
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<tr>
<td>Finland</td>
<td>No specific investment incentives</td>
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<tr>
<td>France</td>
<td>No specific investment incentives</td>
<td>N.A.</td>
<td>N.A.</td>
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<tr>
<td>Germany</td>
<td>No specific investment incentives</td>
<td>N.A.</td>
<td>N.A.</td>
</tr>
<tr>
<td>Greece</td>
<td>No specific investment incentives</td>
<td>N.A.</td>
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<tr>
<td>Hungary</td>
<td>No specific investment incentives</td>
<td>N.A.</td>
<td>N.A.</td>
</tr>
<tr>
<td>Italy</td>
<td>A mechanism for mitigating Market (Volume) Risk is in place in Italy for all regulated activities. The mechanism works by providing <strong>compensation payments to regulated investments, when revenues are lower than had been foreseen</strong>. The mechanism covers missing revenues from capacity allocations in transport and storage investments, covering 100% of capital costs (which entail around 85% of allowed revenues). For compensation on transport investments, the mechanism is managed through the reconciliation of regulatory accounts in year t+2. For storage projects, operators receive compensations for missing revenues and also cannot make extra revenues on top of regulated revenues. In that sense, the mechanism is similar to a revenue cap. The missing revenues are distributed to storage operators as a lump sum in year t+1. The mechanism is financed via an uplift of the transport tariff. For LNG regasification investments, the mechanism covers an (85%) share of missing revenues from capacity allocations. Compensation payments can be made for 3% to 6% of the investment cost. <strong>Guarantee mechanism for decommissioning and clean-up.</strong> The mechanism is designed to cover project promoters from any risk of financial gaps between effectively-incurred costs and the amount set aside through regulated revenues. If the gap is positive (that is, if operators are out of pocket), the Cassa Conguaglio per il Settore Elettrico (CCSE) must finance the difference (payment to operators). If the difference is negative, companies must pay the corresponding amount. The mechanism is financed through uplift on the transport tariff of allowed recoverable revenue. The incentive is automatically in place and applicable to investments during their decommissioning and clean-up phases. The decision on whether payment of a (positive and negative) difference is to be paid is taken based on a calculation of the difference between effectively-incurred costs and the allowed regulated revenues. The incentive is automatically in place and applicable to investments during their decommissioning and clean-up phases. The decision on whether payment of a (positive and negative) difference is to be paid is taken based on a calculation of the difference between effectively-incurred costs and the allowed regulated revenues. The incentive is automatically in place and applicable to investments during their decommissioning and clean-up phases. The decision on whether payment of a (positive and negative) difference is to be paid is taken based on a calculation of the difference between effectively-incurred costs and the allowed regulated revenues.</td>
<td>Based on the regulated costs agreed between the investor and the NRA, compensation payments are automatically provided if the returns on investment are lower than agreed.</td>
<td>The NRA (AEEG) agrees the regulated cost base of investments and provides compensation payments to the investor. The CCSE - the Equalization Fund for the Electricity Sector (CCSE) is a public non-profit organization. It collects the tariff components by operators (in this case, the transport tariff); the CCSE subsequently grants compensation to operators if required, and receives in some instances. The CCSE is supervised by the NRA and the Ministry of Economy and Finance.</td>
</tr>
<tr>
<td>Member State</td>
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<td></td>
<td>An output-based incentive is also in effect: <strong>Payments for the achievement of milestones for investment delivery.</strong> Milestones are set in the planning stages of investment cycles; if those milestones are achieved, project promoters are rewarded; if the milestones are not met, the project promoter is penalized.</td>
<td>The milestones are set and agreed between the NRA and the project promoter during the project planning stage. This involves setting the date and the specifications of the works to be achieved at that particular time.</td>
<td>The NRA – involved in setting milestones during the project development phase; and the provision of rewards/payments and fines. The project promoter is also involved in the milestone-setting process.</td>
</tr>
<tr>
<td></td>
<td>An input-based incentive is also in effect for new investments – a <strong>Cost-Plus Incentive.</strong> Some categories of investments are granted additional remuneration on the WACC base for a specified period of time. Different investments are eligible for different levels of incentive support, depending on the investment type and objectives:</td>
<td>The Cost-Plus Incentive is automatically provided to investments of specific types. In the project development phase the NRA clarifies the purpose of the investment and according to its specific characteristics the allowed revenue rate for the investment is determined.</td>
<td>The NRA defines the categories of investments which are eligible to receive Cost-Plus benefits. It also specifies the level of additional revenue (that is, the % increase allowed on the WACC), and the incentive duration. The NRA is also responsible for revising the categories, WACC increase percentages and incentive durations during each price control, if a revision is required.</td>
</tr>
</tbody>
</table>
|              | **Gas transport investments**  
- Projects for security of supply, gas quality and market support which do not involve additional network capacity receive a 1% increase on the WACC for 5 years;  
- Projects which increase regional network transport capacity receive a 2% increase on the WACC for 7 years;  
- Projects which increase national network transport capacity receive a 2% increase on the WACC for 10 years;  
- Projects which increase national network transport capacity which is ancillary to gas imports receive a 3% increase on the WACC for 10 years; and  
- Projects which increase entry capacity at the country´s borders, or investments related to interconnections of gas networks with LNG floating storage capacity and regasification units, all receive a 3% increase on the WACC for 15 years. |                                |                                |
|              | **Gas storage investments**  
- Projects to increase the storage capacity of existing gas fields receive a 4% increase on the WACC for 8 years; and  
- Projects for new storage fields and peak shaving plants receive a 4% increase on the WACC for 16 years. |                                |                                |
|              | **LNG regasification capacity investments**  
- Projects which increase the load factor without capacity development, or capacity developments of less than 30%, are eligible to receive a 2% increase on the WACC for 5 years; and  
- Projects which increase entry capacity at the country´s borders, or investments related to interconnections of gas networks with LNG floating storage capacity and regasification units, all receive a 3% increase on the WACC for 15 years. |                                |                                |
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<td>No specific investment incentives</td>
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<td>N.A.</td>
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<tr>
<td>Lithuania</td>
<td>No specific investment incentives</td>
<td>N.A.</td>
<td>N.A.</td>
</tr>
<tr>
<td>Luxembourg</td>
<td><strong>WACC increase.</strong> Investments in cross-border interconnections which improve security of supply are eligible to receive a 0.6% increase in the WACC from the point of commissioning of the asset. The incentive has duration of 10 years.</td>
<td>Cross border interconnections automatically receive a 0.6% increase in their WACC for a period of 10 years.</td>
<td>The NRA adjusts the WACC calculation formula for such projects, and ensures that the costs recovered by the promoters of such projects include the value equivalent to a 6% WACC increase.</td>
</tr>
<tr>
<td>Malta</td>
<td>No specific investment incentives</td>
<td>N.A.</td>
<td>N.A.</td>
</tr>
<tr>
<td>The Netherlands</td>
<td>No specific investment incentives</td>
<td>N.A.</td>
<td>N.A.</td>
</tr>
<tr>
<td>Northern Ireland</td>
<td>No specific investment incentives</td>
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<tr>
<td>Poland</td>
<td>No specific investment incentives</td>
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<tr>
<td>Portugal</td>
<td>No specific investment incentives</td>
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<tr>
<td>Romania</td>
<td>No specific investment incentives</td>
<td>N.A.</td>
<td>N.A.</td>
</tr>
<tr>
<td>Slovakia</td>
<td>No specific investment incentives</td>
<td>N.A.</td>
<td>N.A.</td>
</tr>
<tr>
<td>Slovenia</td>
<td><strong>Incentives for anticipatory investments.</strong> If an anticipatory investment is of high importance and/or urgency, various incentives can be used to ensure that the investment proceeds. Specifically, additional returns on capital, shorter depreciation rates and the recognition of efficiently-incurred costs before project commissioning are three incentives that can be granted to support the investment.</td>
<td>The Slovenian NRA is generally of the view that anticipatory investments should be avoided or minimized. However, for essential anticipatory investments, the NRA may decide to provide the project promoter with one of the three incentive mechanisms (depending on the level of risk that it considers exists). In some instances where an</td>
<td>The NRA – has responsibility for identifying the level of necessity of anticipatory investments, and based on that, has the role of deciding whether (1) additional returns on capital, (2) shorter depreciation rates, or (3) the recognition of efficiently-incurred costs before project commissioning, should be provided to a project promoter.</td>
</tr>
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<tr>
<td>Spain</td>
<td>No specific investment incentives</td>
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<tr>
<td>Sweden</td>
<td>No specific investment incentives</td>
<td>N.A.</td>
<td>N.A.</td>
</tr>
<tr>
<td>United Kingdom</td>
<td>No specific investment incentives</td>
<td>N.A.</td>
<td>N.A.</td>
</tr>
</tbody>
</table>

Incentive is granted to a project promoter, the NRA may also require the project promoter to carry some degree of the project risk. The NRA also decides the level of risk that project promoter should take on.
Below, the experience with the use of regulatory incentives for stimulating investment in energy infrastructure has been presented for seven EU member states; experience with the use of regulatory incentives in some non-EU countries is presented in Annex 3. However it must be noted that the detailed back tracking of national experience in this regard is not always possible and some countries do not use or have only recently designed their regulatory incentive schemes.

**The Netherlands**

*General*

The Dutch regulator has experience in incentivizing a cross-border large energy infrastructure project (e.g. NorNed, high voltage DC submarine power cable between Norway and the Netherlands). In 2004 in order to stimulate this investment the Dutch TSO was given several incentives, including one on the timely realization of the project. The incentives consisted of the application of sharing mechanisms in the form of a penalty-reward scheme. Targets set in the regulatory approval of the investment by the Dutch regulator included the overall investment costs, the date the cable went into operation and the availability of the cable. Any deviations of the actual approved range of cost levels were shared equally by the network operator with its customers over the next regulatory period. To stimulate the NorNed project the Dutch regulator set five operational incentives for the Dutch TSO being one of the project developers:

- Bonus/malus based on realised investment expenditure.
- Bonus/malus based on the date the cable became operational.
- Bonus/malus based on realised capacity.
- Bonus/malus based on operating efficiency.
- Pre-set budget for operational costs in the first years of operations.\(^{54}\)

In 2013 the Dutch regulation was adjusted so that it responds better to the challenges of the regulatory period 2014-2016. With regard to regulatory incentives it is worth noting that there will be two categories of expansion investments: regular and non-regular investments. Non-regular investments stem from a new law requiring the regulator to remunerate through yearly tariffs very large or exceptional investments. Regular investments will include all other expansion investments. The regulator intends to include estimated costs from regular investments in its calculation of allowed revenues, while non-regular investments will be remunerated each year on top of allowed revenue. A TSO developing a non-regular investment can apply for a revenue increase each year while the tariffs are set. The label of non-regular investment will be attributed by the Dutch Ministry of Economic Affairs.

*Effect on investment volume*

Investments delivered by the Dutch TSOs are increasing. According to the NRA, the regulation does not affect negatively the financial situation and investment decision of the electricity TSO and the DSOs of both sectors. The investment made allowed the reliability of the network to be maintained. However, the TSO does not share this view, claiming that the cost recovery methodology, which implies low returns, increases financing problems and requires shareholders to provide additional funding. Private financiers believe the rate of return is too low; and public bodies encounter budget deficits as a consequence, making them reluctant to become involved.

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\(^{54}\) The Netherlands – submission of the NRA’s answer to ACER on the TEN-E art. 13 related question, June 2013.
**Difficulties and side-effects**

Setting and implementing operational incentives for NorNed was difficult especially in terms of drawing the targets and drawing the line between the bonus and malus. Therefore, the regulator is not particularly inclined to use these incentives in the future. The experience of the Dutch regulator has led to the conclusion that the optimal approach to large infrastructure investment is a case-by-case approach discarding universal one-size-fits-all solutions.

**Italy**

**General**

The incentive regulation has been introduced in 2000 (replacing the rate of return regulation) and it has been frequently revised and fine-tuned ever since. In gas transmission, the incentives were very generous at the early stage, with an increased remuneration that almost doubled the return on new investments. 60% of the incentive was related to new capacity and 40% to actual flows, to reduce incentives to "useless" assets. Later they were reduced, but maintained. The Italian TSO noticed that this has led to 7 bln euro investment volume over a decade. This is striking as the regulatory asset base of the TSO in 2001 was about 10 bln euro. Capacity increased by 50% and the average tariff decreased by 25% in real terms.

Lately, incentives (so-called extra-WACC or adders) have been maintained and streamlined, with a tendency to ensure their validity for 3 regulatory periods (in total, 12 years) in all sectors. It is felt that the effect of discounting makes them most valuable over the lifecycle of the assets. However, the general tendency is to make the incentives output-based rather than risk-related. Even though the Italian regulator is in general incentive-friendly compared to most NRAs, it also fears the impact of input-based support. This is understandable as even the first years when the incentives to new investment in gas transmission have been applied, investment increased significantly but not enough to meet the regulator´s objective: the entry point capacity. Only later on incentives were "tailored" to the goals and became more effective.

The most relevant experience in terms of strategic investment stimulation is the above-mentioned adders to the WACC. They apply to both gas and electricity network infrastructure and are added on top of the WACC (6.7% at the time when regulation establishing adders was adopted). Additional remuneration is available only for specific classes of development project, mainly those with higher levels of public benefit, aimed at internal congestion resolution or at enhancing cross-border capacity. The adders for the gas transport sector are as follows:

- Replacement investments: 0%.
- Investments for safety, gas quality and market support without transmission capacity increase: 1% for 5 years; from 2014 0%.
- Investments for secondary grid capacity increase: 2% for 7 years; from 2014: 1% for 7 years.
- Investments for primary grid capacity increase: 2% for 10 years; from 2014: 1% for 10 years.
- Investments for primary grid capacity increase aimed at import capacity increase: 3% for 10 years; from 2014: 2% for 7 years.

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55 WIK, C. Müller, New regulatory approaches towards investments: a revision of international experiences, 2011.
• Investments for border capacity increase aimed also at LNG import capacity increase: 3% for 15 years; from 2014: 2% for 7 years\textsuperscript{56}. There is also an ancillary incentive mechanism set in 2010 that allows the Italian TSO to receive the additional remuneration on work in progress (hence before the entry into service of the projects) for a subset of projects. The TSO is only eligible for this adder if it respects each year at least 70% of planned project milestones proposed ex-ante by the TSO and approved by the regulator\textsuperscript{57}. Also in 2010 a mechanism triggering an additional project-specific reward or penalty in case of early or late project completion has been introduced. This is an output-based incentive for accelerating new strategic investment delivery: for a subset of strategic investments the regulator has set milestones for investment delivery; if the project development timetable is not met (if delays occur) and milestones are not achieved the TSO is penalized. The mechanism only foresees the use of penalties as a means to incentivize timely developments; currently there are no rewards at the project level.

The effect on investment volume

The Italian mechanism has been successful in triggering investments\textsuperscript{58} for the electricity sector as well. The evidence presented in the Frontier & Consentec Report shows that this measure has led to the increase in investment volume. The approach is similar to that in the gas sector, even though the objectives of the incentives partly differ.

Belgium

General

High level pass through is the main facilitating factor for energy infrastructure investment in Belgium. Until now, Belgium reduced risks for TSOs through regulation based on periodic revenue cap mechanism with two reassessment mechanisms (ex post): volume correction and settlement mechanism for non controllable costs. However, the TSOs bear the entire risk related to underperformance in achieving efficiency and productivity targets for controllable costs (OPEX with exception of ancillary services). According to the theory of regulation the system applied in Belgium does not encourage investors to enhance the cost efficiency of their investments. In the current regulatory period (2012-2015), the remuneration and financeability of investments have been considered as very low\textsuperscript{59}. The investment trend in the current regulatory period is twice as high as in past regulatory periods (approximately 6% and 3% investment to RAB respectively) but still remains relatively low. The Belgian regulator’s experience in incentivizing infrastructure investment led to a conclusion that there is no need for any special incentives for PCIs. However, in order to enable investment made in cooperation with countries within different regulatory frameworks (e.g. the UK), it is ready to apply new rules. Flexibility in this regard aims at “bridging the gap” in the conditions of regulatory asymmetry and agreeing on terms for construction of submarine interconnector between Belgium and the UK. This flexibility goes hand in hand with attempts to ensure better stability of the

\textsuperscript{56} Autorita Energia, 2012. Received from: http://www.autorita.energia.it/allegati/docs/11/1199-11TITnew.pdf

\textsuperscript{57} AEEG decision 40/2013/R/eel, http://www.autorita.energia.it/allegati/docs/13/040-13.pdf available only in Italian

\textsuperscript{58} Italy – submission of the NRA’s answer to ACER on the TEN-E art. 13 related question, June 2013.

regulatory framework. Since 2008, the Belgian regulator applies a 4-year tariff period instead of 1-year periods.

Effect on investment volume

The effect of regulation on investment volume in electricity and gas sectors is moderate\textsuperscript{60}.

Current and past investment in electricity infrastructure in Belgium includes mostly upgrade and replacement projects. In the current period, the Belgian electricity TSO forecasts a strong regular investment increase explained by the development of onshore wind and PV projects and the phase-out of nuclear.\textsuperscript{61} Additional investment is planned in off-shore and interconnection capacities, namely offshore connection platforms, NEMO and ALLEGRO projects. The volume of planned investment is not directly linked to existing regulatory incentives.

Difficulties and side-effects

The pre-cap and floor regulatory incentives were considered to be inadequate for projects developed between Belgium and the UK due to asymmetry in regulatory framework. Moreover, project promoters may face uncertainty related to the stability of rate of return calculation methods, long depreciation period and the lack of a mechanism to include OPEX-related risks in the rate of return calculation. Investors are tempted to invest in replacement, business-as-usual projects rather than in new, innovative (namely off-shore, HVDC) ones.

The shortening of the depreciation period is not certain for many projects. Uncertainty leads to the same effects as a disincentive through maintaining an excessive depreciation period duration (up to 50 years). This is common especially in cases of projects for which reliable long-term forecasts on use and life time of assets are difficult or do not exist.

Efficiency targets applied on controllable costs (OPEX) may be perceived as too difficult to meet, and cause uncertainty of cost recovery, especially in the case of large projects or projects involving innovative infrastructure. Therefore, the only Belgian electrical energy TSO is more prone to invest in replacement projects than in new and/or innovative ones. According to the TSO the current regulatory framework might need some adjustment in order to raise capital and enable the timely delivery of PCIs.

The UK

General

The UK has a long tradition in the regulation of energy markets and has continually enhanced its regulatory approach. Between 1948 and 1990 the UK energy sector was nationalised. All the investment plans would be made at the central level and price setting based on a “cost-plus” formula reflecting the overarching aim to increase social welfare. Then, in the 1960s and in order to better manage the public expenditures on energy infrastructure, the UK government took on the regulation in the form of Treasury monitoring and assessment of major investment projects. Efficiency and the timely realisation of investment and operation of energy utilities were assessed by the Monopolies and Mergers Commission (today the Competition Commission).

\textsuperscript{60} Elia group, Interim Report, 29 August 2013.

\textsuperscript{61} CREG, Annual report, 2013.
The following descriptions refer to regulations concerning onshore networks in Great Britain. In 1990 the incentive regulation was introduced and was based on the “RPI-X” formula. Between 1991 and 1992 the X factor for transmission prices was set at 0% and then increased to 3% for the period 1993 to 1996. The inflation was below 3% for three of four regulatory years. This affected the transmission prices in the UK that had to be reduced. The initial experience with RPI-X regulation showed that it does not allow striking the right balance between investment and efficiency in times of the restructuring and reorganization of the energy sector. A new regulatory formula was needed in order to make sure that energy companies have capital to take forward investments.

From 1995 onwards, the X factor in the electricity industry was set on the basis of the rate of return on investments and this had a significant and immediate impact on prices. In the UK an ex-ante assessment is made of the service provider’s forthcoming investment volume, and on the basis of that, the allowed revenue cap is established (following a quantification of the capital costs which will be incurred). TSOs can freely choose the optimal projects within the established volume. The UK regulator tried in this way to encourage the accurate forecasting of capex ex-ante and efficient spending ex-post. Between 2002 and 2007, the WACC and the X factor in the gas sector (both for TSOs and DSOs) were set at 6.25% and at 2% respectively, and did not change over the period. Within electricity transmission, the WACC was 6.25% in 2001 and increased to 6.9% in 2007, while the X factor was reduced from 3% to 2%. The WACC for electricity distribution was raised from 6.5% to 6.9%, while the X factor was 3% until 2005 and was then set to zero.

Currently the OPEX of the UK TSO are incentivized by sliding-scale schemes for system availability and for system operation costs (introduced in 2005). The scheme is based on rewarding or penalizing the operator in accordance with its annual performance in running a reliable network. In 2008, the allowance is given ex-ante and the price control time period was set. It is not related to the type of project but to the efficient costs of projects expected over the next 5 years.

In 2010 Ofgem issued a decision on the review of energy network regulation based on 12 recommendations on a potential new framework: Sustainable Network Regulation using the RIIO model. The two primary driving forces for the review were:

- The changing nature of energy network services and the challenge of sustainability; and
- The need to simplify and address identified concerns with the RPI-X framework.

The effect on investment volume

The investment volume trend is cyclic and its dependence on the regulatory incentives can only be assumed. The caps on revenues are linked to the projected costs and they enable specific allowances for investment. At the same time under this approach the efficiency gains are immediately passed through to customers.

The UK regulation ensures a high degree of remuneration and financeability for investments thanks to the high rate of return. According to the theory of regulation, the UK approach ensures a medium to high level of risk placed on the TSO, medium to high incentives for cost reduction and a medium to high transfer of efficiency gains and

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62 WIK, C. Müller, New regulatory approaches towards investments: a revision of international experiences, 2011.

redistribution to final users\textsuperscript{64}. Due to a relatively complex incentive structure, the network operator may face trade-offs between the different incentives for the different cost-components.

According to Ofgem, the ‘RPI-X’ regulatory framework has served consumers well, delivering lower prices, better quality of service and more than GBP 35 billion in network investment since privatisation\textsuperscript{65}.

\textbf{Difficulties and side-effects}

According to Ofgem RPI-X was designed for a very different market and political conditions and may not be sufficient “to encourage network companies to deliver a sustainable energy sector and provide value for money”\textsuperscript{66}. A number of concerns have arisen with the RPI-X framework over time, including:

- Insufficient focus on output delivery, as RPI-X was burdensome and not ensuring the right balance between cost saving and quality of service.
- Uncertain effects of regulation due to scarce information about the consumers’ needs.
- Static focus on regulatory framework based on 5-year price control periods did not reflect the dynamic nature of today’s market.
- The impact of the timing of price-control review on the company decision-making process was strong and did not always lead to optimal choices.
- 5-year price control periods deviated the focus of companies, shifting it too much to the cycles instead of asset and delivery planning.
- The regime became overly-complex as it was developed and adjusted over time.
- Experimenting with smaller parts of the regulatory framework did not consider the general impact of the overall regulation\textsuperscript{67}.

The new RIIO regulation is supposed to build on the successes of past experience but also take the abovementioned drawbacks into account in order to avoid repeating them in the future. It should be noted that the new RIIO regulation increases the length of the regulatory period, and now stands at 8 years.

\textbf{Estonia}

\textit{General}

There is no specific incentive scheme to stimulate investment in the gas or power sectors. The Estonian regulator has some experience in dealing with congestion problems. One of the regulatory challenges for the NRA was to manage congestion between Estonia and Latvia. Before the interconnector between the two countries - Estlink 2 - was put into operation, the Estonian regulator recommended the TSO to hedge its risks related to congestion costs and day-ahead congestion pricing. The TSO had been advised to introduce long-term tools for congestion management such as

\textsuperscript{64} Glachant et al., 2013.

\textsuperscript{65} Ofgem, RIIO – a new way to regulating energy networks, Final decision, October 2010.

\textsuperscript{66} Ibidem.

\textsuperscript{67} C. Jenkins, RIIO Economics, Examining the economics underlying Ofgem’s new regulatory framework, 2011.
Physical Transmission Rights between Estonia and Latvia. Income from the congestion rates is taken into account by the regulator when setting network tariffs\textsuperscript{68}.

Estonia’s experience comes from the time when it built a merchant interconnector with Finland (Estlink). While building Estlink, exemption from the general regulatory framework was granted for the initial years (7-10) before making the interconnector a regulated asset. Estlink was the first project to be granted exemption from article 7 of the Regulation 1228/2003. Estlink remained a merchant project from 2006 until 2013 when it became a regulated transmission line. Regulatory holidays applied by both the Estonian and Finnish NRA served in this case as an incentive mechanism boosting commercial investment. The investment could not be realized under the regulated investment scheme because in 2005 both TSOs had declared different priorities in their investment plans and could not include the submarine cables within them\textsuperscript{69}. At the time of deciding about the Estlink investment the regulator did not consider any socio-economic benefits of the project when deciding about delegating the project’s delivery to merchant developers.

**Effect on investment volume**

The effect of the regulatory framework on investment volume is moderate. The survey showed that there are limited expectations from the investors in the gas sector that the regulatory incentives, other than streamlining of permit granting procedures, will stimulate future investment in big infrastructure projects.

In order to grant exemptions to the Estlink project several criteria must have been assessed and decided upon. The evaluation of the level to which Estlink would enhance competition in power supply, the level of risk high enough to make exemption a necessary prerequisite for investment, unbundled ownership at least for the duration of exemption, charges levied on users, investment not covered in any part by regulated tariffs and the impact of competition. All of these criteria must have been fulfilled and duly-proven. This has been done with the joint effort of the Estonian and Finnish NRAs, governments and developers.

The Estonian authorities did not pay attention to the potentially-adverse effect of the fact that one of the companies participating in Estlink was part of a holding company which also contained the Estonian TSO. Such a situation may result in a potential conflict of interest for the holding company between the commercial activities of the merchant interconnector and the TSO activities. It is also self-evident that such an investment scheme is not optimal for boosting competition or for the effective functioning of the internal electricity market\textsuperscript{70}.

**Spain**

*General*

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\textsuperscript{68} M. Ots, Latest development in Estonia, Estonian Competition Authority, Tallinn November 2013.


\textsuperscript{70} Ibidem.
Spain switched from rate of return to incentive regulation in the late 1990’s in electricity and in the early 2000s in the gas industry. The Spanish regulator adopted a revenue cap mechanism for electricity in 1998, for gas distribution in 2001 and for gas transmission in 2002.

Spain has an interesting experience with incentives for the development of RES. The feed-in tariff system proved to be overly-generous and ill-designed, leading to speculation, boom and bust cycles and a tariff deficit. By the provisions of Royal Decree 1/2012 Spain put ‘on hold’ subsidies for all new investment in all types of RES in 2012. New plants are not admitted to receive support. The current situation in the Spanish energy market and regulatory framework has led to a considerable tariff deficit (the difference between the costs of producing power and the revenue obtained from regulated supply prices was recently estimated at more than 26,000 million Euros). It is supposed to be tackled through measures adopted in Royal Decree-Law 9/2013 passed on 12 July 2013. The new legislation abolishes the remunerative system based on a regulated tariff for energy generating units in supported RES and CHP, and replaced it with a specific remuneration based on market price standard investment capex and OPEX. It has been commented by some industry analysts that the Spanish government’s above-described modifications to the remuneration of existing RES power plants is a dangerous precedent that might discourage investors.

New investment regulations are under consideration, and it is being proposed to introduce a penalty mechanism in which a developer may need to pay a financial penalty if the project is not developed in a timely way (against specific timeline dates). This is to be confirmed and is not currently applied.

**Effect on investment volume**

The effect on the regular electricity transmission investment volume is moderate.

Subsidies in the form of feed-in tariffs (FIT) for different types of technologies have been very successful in fostering investment in clean energy and have produced a large increase in renewable capacity. The share of RES in 2005 accounted for 15% of overall power generation; in 2011, it accounted for 33% and it is expected to reach 41% by 2020 (Eurostat 2012; EWEA 2011).

**Difficulties and side effects**

An electricity interconnector between the island of Mallorca and Valencia could be a good example of a project in which the risk of delay has been realized. The project has seen considerable changes in the planning and timing of its development (4 changes to date) due to technical difficulties. This experience challenges the position of the Spanish regulator according to which “the regulatory regime itself constitutes a very significant incentive, since it establishes a playing field where there is no risk for promoters to invest in infrastructure included in the NTYND Plan”.

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71 Eurelectric Powering investment.

72 V. Romani, L. G. Bueno, Royal Decree-Law 9/2013, of 12 July, whereby certain urgent measures are taken to ensure the financial stability of Spain’s electrical system: Modification of the special regime.

73 JonesDay comments, Spanish government modifies the remuneration of existing renewable energy plants, July 2013.

74 Spain – submission of the NRA’s answer to ACER on the TEN-E art. 13 related question, June 2013.
New regulation introduced in 2012 has eliminated the incentives for new investment in RES, but the feed-in tariffs to existing assets are still the major component affecting the electricity cost structure in Spain (44% of the access charges projected for 2013). The Spanish regulator, which sets the feed-in tariffs, has difficulties in fixing and maintaining the adequate price for all technologies over time.

**France**

**General**

Since August 2013 CRE (the French NRA) may grant a premium to electricity interconnection projects depending on the social welfare generated by the interconnector and on RTE’s (the TSO) performance on costs, delays and trade flows. Interconnection projects require, among other things, specific efforts from RTE, in particular overcoming difficulties related to coordination with its counterparts in neighbouring countries, administrative authorisations, local acceptance of works and the technical challenges involved with natural obstacles. Additional remuneration for RTE is not based on any risk considerations.

The incentive mechanism is based on the assessment of the value of new interconnection infrastructure for the European electricity system and aims to:

- Stimulate interconnection projects that are useful for the community.
- Encourage RTE to carry out investments under the best cost and time conditions.
- Encourage RTE to properly operate newly-created interconnectors, in particular with regard to the additional trade flows brought by the structure.

CRE will grant incentives on a case-by-case basis and will set detailed calculation terms in an ad-hoc tariff decision. The financial incentive for interconnection investments will take the form of a fixed annual bonus in euros, defined ahead of the investment decision depending on the value of the interconnection for the community. Incentives to minimise costs and the time required to complete interconnections, as well as the incentive to properly manage them, will take the form of variable bonuses that will be added every year to the fixed annual bonus. Since the incentive is positive, RTE is guaranteed to receive a payout that is at least equal to the applicable WACC. The incentive mechanism therefore does not introduce any additional risk for RTE. All bonuses will be paid to RTE after the commissioning of the interconnection, for a maximum duration of ten years. The calculation terms for the different bonuses are described below.

1. **Incentive for carrying out investments useful to the community**

The level of fixed bonus granted to RTE will be determined by taking into account the value of the interconnection for the European electricity system, which will include quantifiable elements, but also qualitative elements such as the security of supply. The component quantifying the usefulness of the interconnection for the electricity system will be assessed taking into account in particular:

- A yearly estimation of additional trade flows generated by the interconnection.
- A forecast of market prices in the two interconnected countries after the commissioning of the interconnection.
- An estimation of investment costs.

This assessment will be taken into account as an indication of the value created by the project for the community, a fraction of which will constitute the incentive granted to RTE.

2. **Incentive for carrying out investments at best cost**
RTE will provide CRE with its best estimate of the investment costs for the given interconnection project. The lower the costs, the higher the bonus will be (and vice versa). The bonus related to costs will depend on the difference between the forecast and actual budget, and will reflect the benefit for the community as a result of the variation in the investment costs.

3. Incentive for optimal operation of the interconnection

Once the interconnection is commissioned, the trade flows it creates will be compared to the flows announced by RTE before the investment decision for the year in question. The bonus will depend, similar to the bonus relating to costs, on the variation in usefulness for the community as a result of a variation in trade flows. The more the actual trade flows exceed the trade flows forecast by RTE, the greater the bonus.

4. Incentive for carrying out investments within the shortest possible time period

Since RTE’s capital cost is already covered by the allowed return (WACC) on the RAB, financial incentives will constitute an economic benefit for RTE. The sooner RTE manages to obtain the financial incentives, the higher their value. The incentive for carrying out investments within the shortest possible time period is therefore implicit since the fixed bonus and bonuses related to costs and flows is paid when the interconnection is commissioned.

4.4 Best practice use of regulatory incentives

The optimal approach to selecting and using regulatory incentives to address (excessive and unacceptable) PCI risks is considered here. Firstly, some of ACER’s main recommendations regarding incentive selection are highlighted; following that, some examples of best practice use of regulatory incentives in individual EU Member States are presented.

As a general guideline, ACER recommends that NRAs bear in mind the following overall principles when considering incentives for PCIs (with excessive risks):

- Monetary compensations in the framework of Article 13 of Regulation (EU) No 347/2013 should not be granted for risks which are already reflected in the allowed cost of capital;
- The incentives should reflect the PCI’s specific risk level (borne by project promoters); that is, a case-by-case approach should be employed;
- The subsidies, grants and cost-allocation contributions received by a project already should be taken into consideration when deciding on awarding regulatory incentives, to avoid over-compensating project promoters;
- NRAs should assess the justification of the risk profile of a PCI in the context of the net positive impacts brought by the project;
- NRAs should quantify in monetary terms the value of the (potential) incentives to be granted to the project promoter and the resulting overall compensation, and compare this with the project’s overall benefit as calculated in the project cost-benefit analysis.

Our analysis has identified some best practice cases in the use of regulatory incentives to address specific regulation-controlled risks. Whilst these are country-specific examples, the means by which each incentive operates is worth considering because the lessons can be learnt and applied in other country contexts.
- **Increase in WACC for investments in new technologies which store electricity to help offset unknown OPEX risks**
  Selected energy storage projects promoted by the Italian electricity TSO Terna are eligible to receive a +2% WACC increase for a period of 12 years. Note that over the 12-year period in the Italian regulation only the WACC premium is stable, the base WACC varies over the regulatory periods. Electricity storage technologies are often innovative technologies at commercial scale, and this may lead to risk of OPEX overrun. Italian regulation foresees WACC surcharges also for other regulated businesses; however, that envisaged for electricity storage is arguably the only one motivated by higher risk incurred by the project. The rationale behind this incentive is that electric storage has a very high technology and OPEX risk and so it would not be undertaken without such incentive.
  Terna indicated in its 2011 Development Plan a target of investing in energy storage capacity for 130 MW. Only 35 MW of the planned 130 MW are eligible for the WACC increase, provided that they meet some conditions (storage facilities should be removable and should be necessary to allow the injection into the grid of electricity generated by intermittent renewable sources). In addition, Terna's 2012-2015 Defence Plan, which was approved by the Ministry in October 2012, foresees further investment in power intensive storage capacity for 40 MW power; among these only 16 MW will be granted the WACC surcharge.

- **Use of a sliding scale adjustment mechanism to offset the risk of under-recovery of costs (volume risk) in Germany.** Investments in electricity infrastructure in Germany benefit from a review (at the end of each regulatory period) of the revenues received during the same regulatory period. The value is compared with the level of allowed revenues (the amount agreed by the developer and the NRA at the beginning of the regulatory period). If actual revenues are outside of the allowed range the project developer has a right to receive (or must pay) the difference, depending on whether its actual revenues were lower (or higher) than the sliding scale band/value. Any difference between allowed and received revenues is not paid as a ‘lump sum’ single payment, but instead is duly incorporated into the calculation of allowed revenues for the next regulatory period.
  This mechanism allows electricity infrastructure project developers in Germany to be sure that they will receive a certain level of revenues. Specifically, if the use of the asset is lower than forecast, project developers will not face severe project cash flow problems, because the volume risk is shared between the project developer and consumers.

- **Provision of clear rules and advice over anticipatory investments to avoid the development of projects with stranded costs in the Czech Republic.** The Czech NRA provides explicit advice to potential project developers regarding the type(s) of investments it favours, based on its view of the optimal future development of the electricity infrastructure network. In particular, the Czech NRA develops a 10-year infrastructure development plan which details the projects which are eligible for inclusion in the TSO’s regulatory asset base; by implication, the NRA also therefore indicates which investments costs do not qualify for...

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75 Italian NRA’s resolution 288/2012/R/eel (http://www.autorita.energia.it/it/docs/12/288-12.htm)

76 The target indicated in the 2012 Development Plan, which is not yet approved by the Italian Ministry for Economic Development, is 242 MW.

77 Italian NRA’s resolution 43/2013/R/eel (http://www.autorita.energia.it/it/docs/13/043-13.htm)
inclusion in the regulatory asset base and which are not considered by the NRA as being favourable investments.

- **Ability to retain any CAPEX cost savings achieved during the development and construction phases of projects in Portugal**, in order to help projects remain financially liquid during their construction phases. In Portugal, if a project promoter achieves cost savings beyond the regulated standard or efficient costs for the investment, they can receive: (1) an increase/decrease in the RAB of up to 5% of the investment value, and/or (2) a premium of 150 basis points from the WACC for the regular RAB.

In 2013 a total investment volume of €119.5 million was made in energy transmission networks.\(^78\)

- **Use of longer regulatory periods to help avoid investments becoming inefficient in Croatia.** In making gas distribution infrastructure investments, Croatian DSOs can open a ‘regulatory account’ which normalises (freezes) the allowed revenues for the project over the entire project lifetime. Specifically, revenues are frozen for a minimum 8-year period, and up to a maximum 30-year period, depending on the asset lifetime.

Whilst it is feasible that regulated tariffs could rise over time (which would lead to higher-than-planned revenues for an operating project), it is also possible that tariffs would decrease with time. By freezing (normalising) tariffs for an investment over its entire operating period through the use of a ‘regulatory account’, the risk of the investment becoming comparatively ‘inefficient’ is addressed.

By freezing an investment’s allowed revenues throughout the entire project lifetime, a DSO is guaranteed to receive the income stream which was agreed prior to commissioning. The revenues of a particular investment are likely to vary depending on when the investment is commissioned. Hence, whilst it is possible (and likely) that an operating project may become cost-uncompetitive in comparison to projects developed at a later date and which are more efficient, the risk that such a situation results in revenue losses (and problems recovering the investment cost of capital) is effectively-mitigated.

It is understood that this regulatory incentive has helped incentivise investments in distribution infrastructure projects in Croatia and has prevented discrimination between DSOs on the basis of the timing of project commissioning.

- **Early recognition of costs to address liquidity risks during the project construction phase in Italy.** The Italian NRA uses a mechanism to allow the TSO to benefit from the early recognition of construction costs of capital in electricity infrastructure investments. That is, the TSO obtains remuneration on works in progress (i.e. recovers costs incurred in the period up to project commissioning). The incentive is available for a subset of investments, and the early recognition (and recovery) of costs is conditional on the TSO’s meeting at least 70% of planned project development milestone deadlines. The specific milestones for each project are proposed, ex ante, by the TSO and approved by the NRA. The incentive mechanism is designed to promote investments by the TSO (to incentivise the TSO to deliver the necessary volume of infrastructure investments) by addressing liquidity risks encountered during the construction phase of projects. That is, by allowing construction costs to be recovered at an early stage, sufficient financial income should be obtained to be able to continue

paying project construction costs without creating an overall debt on the project finance balance sheet (i.e. project finances remained liquid).

The Italian NRA considers that this regulatory incentive, in combination with certain other regulatory incentive mechanisms, has helped realise the significant volume of infrastructure investments that was deemed to be required in Italy in recent years. Looking forward, a significant volume of investment in electricity transmission infrastructure is planned in Italy: Terna S. p. A., the main grid owner, has set out in its 2014 Development Plan, with a goal of developing transmission project investments totalling €8.1 billion (of which €5.6 billion will be made in the next 10 years).79

- **Use of an OPEX sliding scale mechanism to address OPEX overruns in the United Kingdom.** Sliding scale regulatory incentives are in place for electricity TSO system OPEX costs in the United Kingdom. The sliding scale mechanism is designed to reward and/or penalise the TSO in accordance with its annual performance in running the network. The specific risk of OPEX overruns is addressed (or at least reduced) by the regulatory incentive, providing that actual OPEX costs are outside the pre-defined sliding scale range, the cost difference will be shared between the TSO and its customers.

For the previous regulatory period, the OPEX cost range was set ex ante for the regulatory period beginning in 2008; the timings of OPEX price controls were set at the same time, based on the anticipated efficient costs of projects over the following 5-year period.

GBP 1.7 billion capital investments in electricity transmission infrastructure were made in the UK in 2012/2013.80 In the period 2013 to 2021, National Grid, the transmission system operator, in its Business Plan, sets out its plan to develop new electricity transmission infrastructure with combined CAPEX and OPEX of GBP 21.3 billion.81

- **Use of a Cap and Floor revenue regime for new interconnection projects in the United Kingdom.** The UK NRA has announced in August 2014 that it will roll-out a developer-led cap and floor regulatory regime for new near-term (electricity) interconnection projects. In essence, the regime sets maximum (cap) and minimum (floor) level to the revenues accrued by interconnection project developers.82


The levels of the cap and floor will be set up-front and remain fixed in real terms for the 25-year duration of the regime unless specific re-openers are triggered.83

Some of the advantageous characteristics of the regime include:

- The potential to obtain higher rates of return. The NRA proposes to set the cap using the re-gearing equity of an independent generator, which is anticipated to be higher than the notional cost of capital made under the NRA´s normal price controls. Whilst returns up to the cap are not guaranteed, project promoters are incentivised to bring forward commercially-viable projects because there is potential to achieve the cap (and therefore enjoy substantial economic rewards for having made the investment);

- The C&F regime recognises risk specific to cross-border electricity IC projects. Projects are assessed on a case-by-case basis – for example, the assessment of economic need and cost assessment is carried out on a project specific basis. The levels of cap and floor are set based on the efficiently incurred project specific costs (RAV) and on cost of equity and debt benchmarks applicable to all projects. However, developers can request for deviations from the basic C&F regime design where they can demonstrate that it is in the interest of consumers;

- Project costs are recognised at an early stage through the use of ex-ante OPEX and CAPEX assessments; there is also the potential for a project promoter to obtain a cost re-opener where they incur unexpected costs outside of their control (for example, due to bad weather);

- A 25-year regulatory period would be used. Therefore, project promoters would enjoy stability in regulatory conditions over a significant period of time, which reduces the risk of future adverse regulatory decisions impacting on their returns on investment. The project depreciation period would also be 25 years in duration, which is equivalent to a (substantially) reduced depreciation period in comparison to the typically-used onshore price controls (which, in the UK, are around 40 years or more);

- Market (volume) risks to a project promoter are also effectively-addressed by the Cap and Floor regime because the floor provides a guaranteed minimum stream of revenues to the project promoter. Consequently, the project promoter is exposed to reduced (constrained) levels of market (volume) risk, but the floor should ensure that the exposure level is acceptable (and hence incentivises investments in interconnectors).

- **Exemption from regulatory requirements for cross-border investments, due to uncertainty over cross-border cost (and benefit) allocation in Estonia.** During the development of the Estlink interconnection project between Estonia and Finland, the two countries’ TSOs had not agreed on a specific allocation of project costs; consequently, such details were not included in the respective investment plans of each country.

Due to the uncertainty over cost allocation between the two countries, it was decided that, during Estlink´s first 7 operating years, the project would be exempt from having to comply with regulatory framework requirements and that it should be developed as a merchant project. This served to increase private commercial interest in developing the project. After the initial 7-year period as a non-

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regulated investment, the project became a regulated asset. The outcome of the temporary exemption from regulatory compliance was that the project was able to be developed in a timely way; without having taken such a measure, it seems unlikely that the project would have been delivered.

### 4.5 Stakeholder views on Best Practice Use of Regulatory Incentives

Here, stakeholders’ views on the effectiveness of different regulatory incentives are presented.

Stakeholders’ views as resulting from stakeholders’ responses to the project questionnaire are set out below: in Figure 6, the views of all stakeholder groups (considered together) regarding how regulatory risks can be most effectively addressed using regulatory incentives is shown. The degree of effectiveness of each regulatory incentive is reflected by a stakeholder’s view on the extent to which the incentive is required (that is, its level of necessity). In Figure 7, the views of the 14 TSOs answering the questionnaire regarding how regulatory risks could be most effectively addressed using regulatory incentives are shown; TSOs views are then considered in a greater degree of detail in Figure 8 where the views of electricity TSOs and gas TSOs are compared. Lastly, the views of the 9 NRAs answering the questionnaire regarding the most effective means of dealing with regulatory risks are shown in Figure 9.

**Figure 6 : Views on how regulatory risks can be most effectively addressed through the application of regulatory incentives (all stakeholders’ views agglomerated)**

It is immediately notable from the information presented in Figure 6 that there is a significant degree of variation in the views held by stakeholders concerning the degree of necessity of each regulatory incentive. In other words, commonly-held views and unanimous agreement on the degree of necessity of each incentive do not seem to exist. However, it is possible to comment on some general trends in the feedback received from stakeholders. On average, two regulatory incentives seem to be perceived as having relatively high levels of necessity. The first is the early recognition of costs, which 48% of all stakeholders consider to be ‘necessary’ and 41% consider as being ‘useful’. The second is the use of longer regulatory periods and stability provisions, for which some 40% of all stakeholders consider to be ‘necessary’ and 52% consider to be ‘useful’.

*Source: AF Mercados EMI and REF-E analysis, 2014*
Figure 7: Views of TSOs on how regulatory risks can be most effectively addressed

Source: AF Mercados EMI and REF-E analysis, 2014

As a group, TSOs generally consider that most regulatory incentives are, at the least, useful; some regulatory incentives are considered to have a high level of necessity. Only in a tiny minority of cases do TSOs consider a regulatory incentive to be unnecessary.

TSOs also appear to believe that three incentive mechanisms are particularly necessary for PCI risks to be adequately addressed. Specifically, some 57% of all TSO respondents consider the use of higher rates of return (WACC premiums) and longer regulatory periods / stability provisions to be ‘necessary’. 71% of TSO respondents consider the early recognition of costs to be a ‘necessary’ regulatory incentive to address PCI risks.

A comparison of the views of gas TSOs and electricity TSOs, considered as separate groups, is shown in Figure 8.

Figure 8: Comparison of the views of gas and electricity TSOs on how regulatory risks can be most effectively addressed

Source: AF Mercados EMI and REF-E analysis, 2014
In Figure 8 it is notable that there is considerable variation in the views of the two groups, although the degree of divergence of views seems to change depending on the particular regulatory incentive being considered. In general, it can also be observed that, for all regulatory incentives (except in the case of the early recognition of costs where the two groups’ views are almost identical), gas TSOs consider the necessity to be higher overall. In other words, electricity TSOs appear to consider regulatory incentives to have a lower level of necessity overall.

In comparison with TSOs, NRAs as a group appear to consider regulatory incentives to be substantially less necessary for dealing adequately with PCI risks. In particular, for all incentive mechanisms (except higher rates of return / WACC premiums) at least half of NRA respondents stated their view that these were ‘useful’, as shown in Figure 9. Beyond this, most of the remaining respondents considered that incentive mechanisms were ‘not necessary’.

Figure 9: Views of NRAs on how regulatory risks can be most effectively addressed

![Figure 9: Views of NRAs on how regulatory risks can be most effectively addressed](image)

Source: AF Mercados EMI and REF-E analysis, 2014

During the second workshop, it emerged that TSOs would welcome stability provisions as well as mechanisms addressing the liquidity risk, perhaps more than rate of return adders. It appeared also that there is agreement on the importance of stability provisions amongst NRAs as well.

4.6 Conclusions

Chapter 4 of the report has considered regulatory incentives to address risks for PCIs, focusing on the theoretical potential of each incentive, as well as considering present-day examples of the use of incentives in certain EU Member States, and highlighting the views of TSOs and NRAs relating to the potential application of specific incentives.

Each regulatory incentive has a unique potential applicability in terms of the specific risks that it can address. Additionally, different regulatory incentives can potentially be used to treat the same risk. This means that NRAs have flexibility in choosing how to address specific identified risks through using a particular regulatory incentive, if indeed they opt to use incentives. Consequently, a variety of distinct approaches are currently in operation in the various Member States which have opted to use regulatory incentives.
Specifically, individual countries have tailored the design of regulatory incentives to suit their specific conditions and requirements.

Stakeholders within the energy infrastructure investment sector (particularly NRAs and TSOs) have demonstrated their view that certain regulatory incentives have significant potential to help offset risks associated with PCI investments. However, there is no commonly-agreed view regarding the level of necessity of regulatory incentives when all stakeholders’ views are considered together. Broad variation exists in stakeholders’ perceptions. For example, TSOs – which, compared to NRAs, appear to consider the need for regulatory incentives to be high overall – demonstrate notable variation in their views when respondents are split into two groups, those of gas TSOs and electricity TSOs. This variation in the views of stakeholders regarding the optimal use of regulatory incentives fits well with suggestions to apply specific incentives – where they are required – on a case-by-case investment basis. This is in conformance with ACER’s view that in the event that an investment requires regulatory incentive support, the particular incentives to be applied should be based on the specific investment under consideration (that is, a uniform approach to applying incentives for all investments should be avoided).

Despite the variation in different stakeholders’ views on the need to apply regulatory incentives to address PCI risks, the following should be kept in mind within any future efforts to apply incentives to address risks: there is general agreement that the two most necessary regulatory incentives are (1) the early recognition of costs, and (2) the use of longer regulatory periods (stability provisions). Consequently, it is the project team’s view that any future use of regulatory incentives to address PCI risks should focus initially on the use of these two incentives.
Chapter 5 – Recommendations for Guidelines
5. RECOMMENDATIONS FOR POSSIBLE GUIDELINES

5.1 Introduction and main principles

PCIs may face several risks, as outlined in chapter 2. Feedback from stakeholders revealed that so far only two PCIs were identified as likely to be delayed or cancelled due to an unbearable level of risk. However, it is worth noting that TSOs may have no interest in disclosing which projects are in danger of not being implemented on time (as they are trying to source financing for them): so it is difficult to collect evidence of this issue. Notwithstanding this barrier we obtained some evidence on two projects. Additionally, the experience with PCI implementation means it is likely that it is too early to draw any conclusions.

However, our study in chapter 4 showed that several of these risks are mitigated, with good practices already implemented in some Member States, so it may be argued that further measures could amount to a useless and costly burden.

Yet risks might emerge in the near future. We advise taking into account, in a timely way, that the investment tasks that will soon be faced by the European energy industry are substantially harder than in the past, due to:

- the much larger size of investments triggered by the pursuit of environmental, market integration and security of supply goals in the electricity sector, while at the same time the reduced consumption growth decreases the traditional motivation for infrastructure growth, typically alleged to justify financial support of investment decisions; and
- the increasingly integrated and mature gas market, where capacity is going to be largely auctioned and is already often available on a short term basis, whereas long term capacity is subject to congestion management: this enhances competition but reduces the interest of private market players in new infrastructure development – despite the likely growth of peak capacity demand – jeopardising the traditional investment model.

Therefore, the new context poses a difficult challenge for Member States’ as well as European authorities. If the current regulatory framework is deemed adequate and no further specific measures are adopted, but later results do not uphold this judgement, it may then be too late to adopt new measures, given the long lead time of both EU decision-making and of investment implementation. Yet, new measures might be unnecessary, be exploited for strategic behaviour with a view to increase costs and tariffs, and delay processes due to further administrative burdens.

With this dilemma in mind, before any suggestion is put forward it seems appropriate to outline some broad common principles to be adopted in the implementation of article 13.1 of the TEN-E Regulation.

We recommend the following main principles of an appropriate decision-making process on risk evaluation and regulatory incentives for PCIs:

- **Case-by-case analysis and decision.** This stems from the TEN-E regulation itself, which recommends a case-by-case approach, and is confirmed by the results of our research, which shows how different are the risks, and their mitigation practices\(^{84}\). Any simplified approach, like (for instance) awarding higher

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\(^{84}\) In the same line, ACER has also noted that any methodology for the evaluation of investments as well as the relevant risks can only be meaningfully deployed against the background of the respective, overall regulatory
rates of return to certain types of projects, should in general be avoided, as it may lead to unnecessarily higher costs or the duplication of incentives. We do not recommend the generalisation of any specific existing regulatory model or explicit risk evaluation methodology, which could be inappropriate outside its specific framework and (national or cross-border) context.

- **Neutrality of decisions** with respect to all stakeholders, with no privileged consideration of the interests of any stakeholders’ class or nation. This includes the right of all stakeholders to see their interests adequately considered and assessed, and balanced (in the case of conflicts) against those of others by a neutral authority.

- **Transparency** of the decision-making process, with the inclusion of all relevant stakeholders, and continuous provision of information about the following steps, with a substantial participation of European regulatory and financial institutions as well as project promoters. Stakeholders should be informed about the upcoming stages of the process, and consulted regarding them.

- **Fast-tracking of the decision-making process.** As time overrun is often strictly related to cost overrun risk for PCIs, any procedure should speed up the process rather than becoming another step that needs to be ticked off by developers. One pillar of the TEN-E Regulation is the reduction of red tape in the investment decision-making process: the same goal should be achieved as far as regulatory decisions are concerned. This may be particularly true for cross border coordination, which is indeed perceived as the highest risk to PCIs.

- **Stability of decisions.** Most stakeholders fear the regulatory risk arising from future changes in the regulation\(^{85}\), typically due to changes in the decision-making bodies or their decisions being overruled by incoming top regulators (i.e. newly appointed NRA Chairpersons, Boards, and Commissions), higher government levels or Courts. Whereas this may be partly avoided whenever NRAs take longer term decisions (i.e. with effects stretching beyond the next regulatory period), it is worth recalling that a stronger international grounding of decisions often helps improve their stability. In fact, if decisions have been agreed with EU or other national bodies, it is much harder for new regulators or other government levels to undo or modify them, and this helps stability and reduces regulatory risk.

Besides these general principles, any Guidelines must also take stock of the provisions that have been recently adopted, as required by the TEN-E regulation: in particular, the ACER Recommendation (of 27 June 2014). The Guidelines should consider the process envisaged by ACER for the monitoring of PCI implementation and their problems.

Having outlined the main principles for the decision process, in what follows we provide some recommendations regarding the contents of potential guidelines and in particular:

- How the risk evaluation and PCI regulatory assessment methodology may be conceived (section 5.2);
- How to reinforce the institutional setting of decisions (section 5.3);
- How to address what were found to be the most relevant project risks that may be influenced by regulation (section 5.3).

It is hard at this stage to evaluate whether Guidelines by the European Commission regarding the granting of regulatory incentives, as envisaged in article 13.7 of the TEN-E Regulation, should be legally binding. However, the currently limited evidence of delays framework, i.e. by considering the specific way the different components work together in mature national regulatory frameworks.

\(^{85}\) This is the second worse risk feared for PCIs, and is mentioned as serious or overwhelming by 75% of respondents.
and the fact that the risk that PCIs may fail (analysed in previous Chapters) are mostly theoretical, suggests a flexible approach. The legal status could be akin to that of the Guidelines of Good Practice (GPPs) that have been a remarkable feature of the energy market liberalisation processes of the past decade, driven by the Florence and Madrid Regulatory Fora. Such status sees GPPs as non-binding, but their official endorsement (for example as an EC Recommendation) foreshadows that they are indeed a goal of the EU and could be turned into a binding Regulation in case their implementation is not regarded as adequate. Therefore, like the GPPs, these Guidelines should apply to all stakeholders, be sufficiently detailed and easily monitored.

5.2 Recommendations on the common methodology for project risk evaluation

Chapter 3 shows that no already outlined methodology to evaluate project risks has been fully developed yet by NRAs, who currently analyse risk at corporate level (or portfolio level) when setting the beta factor. A sound risk evaluation methodology is necessary in order to provide the basis for preferential regulatory treatment of PCIs, as article 13 of the TEN-E regulation mandates. We have also argued that theoretical reasons justify the inclusion of project specific risk in regulation design, as a holistic approach to risk evaluation may not be efficient. In fact beta factors, as calculated by the dominant CAPM approach to regulated rate of return calculation, only considers the average industry risk, often through averages or medians of international peer samples, and in the best cases only considers individual company risk. This may not be enough to address risks of marginal, possibly controversial and innovative investments like most PCIs, unless other risk mitigation procedures are implemented.

In this situation, a new methodology for risk assessment, as required by the TEN-E regulation, should be developed, with a view to provide the basis for preferential regulatory treatment of PCIs.

Given the very different regimes and mitigation measures already in place, any generalised/simplified approach to risk evaluation would be dangerous, possibly leading to inappropriate incentives, so a case by case approach is preferred. This is in line with the ACER Recommendation, which suggests that the common methodology should consider the distinctive features of, and the measures taken in, different national regulatory regimes.

The risk analysis should be consistent with the CBA, notably for costs; however, the analysis of benefits undertaken by ENTSOs’ CBA has a different focus and should rather be kept apart from risk assessment. This is in line with the Recommendation as ACER observes that results of the CBA can be used in the risk assessment and recommends that the risk assessment, the CBA, the CBCA and the PCI selection process use consistent data and assumptions.

Wherever possible, we recommend providing market-based incentives through participation to congestion rents and other private benefits of the projects. This may also take the form of output-related incentives, based on the valuation of benefits (e.g. from security of supply or other public goods), which could be partly transferred to project promoters by regulatory provisions. However, this approach may not be suitable when results are largely beyond the control of project promoters and the appropriate level of output is not easy to set.

86 See for example the Position paper “Financing of Infrastructure Projects”, submitted by E-Control during the consultations for the present research.
For projects where market - or benefit-based incentives are not appropriate, we recommend outlining a common methodological transparent procedure at the EU level, rather than a precise quantitative risk assessment exercise or explicit risk evaluation. The procedure should clearly outline which are the steps to be undertaken to assess project risk on a case by case basis.

A more quantitative risk analysis methodology, with results based on statistical evidence and/or expert judgements should be developed in due course, if a process for its development is launched, for example by ACER. Yet, undertaking such methodology at this stage as a condition for an improved regulatory framework would be a time- and money-consuming process. In any case, we suggest that such an explicit risk-evaluation methodology cannot be the basis for the mechanical implementation of incentives. The ACER Recommendation is consistent with this approach since, as far as the risk evaluation is concerned, it sets the steps to be undertaken to perform the evaluation of the risks faced by project promoters (see Chapter 3 above).

5.3 Institutional issues

At this stage, the procedure would be better defined at EU level, but it could only provide a non-binding guidance to NRAs and stakeholders. As suggested above, it should have a similar legal status to the regulatory GGPs, and be turned into a legally binding instrument in case of significant lack of compliance. The step-wise common risk evaluation methodology proposed by ACER in the Recommendation is in-line with this view, as it is in fact an EU-level-arranged procedure, providing non-binding guidance.

We consider that the concerned NRAs are the best suitable entities to lead the risk evaluation process and decide whether the project promoter faces higher risk (or not) and consequently is entitled (or not) to appropriate incentives pursuant to article 13.1 of the TEN-E Regulation. In article 13, Member States and NRAs are specifically mandated to ensure the adequate application of any risk-related incentives. ACER assigns a leading role to concerned NRAs with regards to the risk evaluation. According to the ACER Recommendation, the NRAs, starting from information provided by project promoters, should identify the project risks, assess any mitigation or compensation measures (either regulatory or not) already in place, quantify the risk, identify the comparable projects and their risk and finally decide whether the project faces higher levels of risk than a comparable project.

In the current framework, decisions about risk assessment and mitigation lie mostly with NRAs, with a limited role played by national governments, who can mandate the implementation of projects or provide grants and other sources of finance. The European Union and international financial institutions can also contribute to some extent, but their scope to intervene is limited by their budgets. Moreover, since National or European grants are the equivalent of equity financing, they are often a solution with a high opportunity cost for European society, and may also entail market distortions.

In principle, NRAs are neutral bodies that take rational decisions, which balance the interests of all stakeholders. However, in practice they may be subject to pressures from governments and, possibly, selected interests. Whereas these considerations may be seen as academic and not applicable to European NRAs unless adverse evidence is found, what matters is not so much whether NRAs are actually balanced or not, but whether they are perceived as such by project promoters and investors. In fact, as

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interviews and questionnaires of our research have shown, regulatory risk is regarded as a major problem by stakeholders other than NRAs\(^{88}\).

In other words, the above statements do not mean that regulatory risk is necessarily real, but that it may be perceived to exist, notably by investors. The problem of providing reassurance to stakeholders is not new in regulation, but it is probably rather new in energy regulation. For example, central banks have long dealt with credibility problems, and with the need to be perceived as reliable in the longer term. This may seem a matter of lack of rationality, but it is rather related to the typical “bounded rationality” of financial markets, which are key for investment decisions.

Hence, the issue regulators face is how to persuade investors that regulatory risk is minimised, even in the longer term. For example, risky long term investment may face further obstacles if investors think that a favourable regulatory framework will not survive beyond the terms of office of the present Board or Chairpersons of the NRA. This is more likely for exceptional investments than for “business as usual” replacement or enhancement of current assets.

From this perspective, the Guidelines should reduce regulatory risk, which is not necessarily a consequence of a lack of objectivity or bias on the regulators’ side, but possibly of weaknesses of their institutional position, or of the inherent, limited duration of terms.

On the contrary, the Guidelines should aim at strengthening the cross-border and European rather than the national rooting of regulatory decisions: this would reinforce their independence and stability. In fact, it is always harder to modify an international agreement than a national decision, as the consent of the concurrent parties would be necessary. Moreover, since terms of the NRA’s top management in different countries are not usually the same, the probability of a change – and hence the regulatory risk – would be reduced.

For better transparency and monitoring of the PCI process, we recommend that any risk evaluation decision process pursuant to article 13 of TEN-E Regulation should start from an assessment exercise, including the answers by relevant stakeholders to a set of common questions. This assessment is related to, but does not coincide with, the monitoring required by Article 5.

This exercise would be part of the process envisaged by the TEN-E Regulation, Article 5, notably paragraphs 3, 4 and 5.

With a view to a streamlined assessment, the Guidelines may suggest that the exercise should include risk evaluation by NRAs, TSOs, financial institutions and other stakeholders, including:

- The risk typologies faced by each PCI, which could be taken from the list of typologies described in Chapter 2, e.g. by classifying the risk as negligible, serious, crucial, or already mitigated;

- The risk mitigation or rewarding instruments that are implemented for the PCIs and those that would be required or are not necessary. These could be taken

\(^{88}\) See Chapter 2 for details.
from the list of instruments suggested in Chapter 4, including the “best practices” that have been singled out.

An example of the regulatory assessment grid is provided in the Annex 4.

It is worth recalling, and to avoid misinterpretation, that this is only a part of the monitoring exercise required by the TEN-E regulation. Another essential component, which lies beyond the scope of this Report, should be the definition of milestones for each Project, to be identified at the beginning, and of results achieved against them. These could be also the basis for awarding selected incentives.

The analysis of risks should include a common consultation process. We recommend that at the end of the consultation process on risk evaluation, the concerned NRAs call for a final meeting of all the participants in the Project Conference, which is described in the next section.

During the consultation process, in particular, NRAs should provide clear indications on how risks are identified and assessed. The consultation process should gather all stakeholder views, with the aim to promote as much informed and commonly-agreed decisions as possible. NRAs are very accustomed to such consultation practises, so they would be in the best position to lead this consultation process, having all the necessary instruments and expertise. Encouraging a transparent procedure is one of the principles set in the Recommendation.

Both the assessment exercise and the consultation may provide evidence for the possible request of improving the regulatory framework. Any such request should be duly motivated and grounded in thorough analysis, which should be prepared by project promoters, possibly in collaboration with other investors, lenders and other project beneficiaries. In particular, the Project Conference should focus on the identification of higher risks of the PCI under analysis in relation to a comparable project, based on transparent inputs from project promoters.

This is not new in the EU regulatory framework: for example, the award of exemptions from TPA pursuant to Article 17 of Regulation 714/2009/EC and Article 36 of Directive 2009/73 also require the provision of reasons, which are likely to be provided by promoters and other concerned stakeholders at first.

The evidence could come, among others, in the form of business plans and financial models, underlining the market, economic and regulatory conditions that would justify or prevent the implementation and the financing of the project. These plans should specify the main assumptions, including the conditions of comparable projects, and provide a suitable sensitivity analysis.

5.4 Recommendations on the provision of incentives

In this study of all identified regulatory risks the most significant turn out to be cross-border issues and the risk of future adverse regulatory decisions. On the other hand, it is too early to confirm that these (or others) are indeed the most relevant ones, and there is no general consensus about them. Therefore, these recommendations suggest streamlined procedures rather than specific incentives.

In our opinion project risks, and in particular the above mentioned ones, would not be optimally addressed by the use of a specific incentive mechanism harmonised across the entire EU. Specific features of national regulatory regimes should be considered, and certainly cannot be deeply modified for PCIs only. Thus, a regulatory framework suitable for PCIs should be adapted to the existing one, rather than substituting it.
Therefore, in order to implement article 13 of the TEN-E regulation we propose a procedure (section 5.3.1) and some guidance on the incentive design (section 5.3.2).

5.4.1 Procedure

In order to implement article 13 of the TEN-E regulation we propose a procedure to be open for all PCIs, but actually aimed at and is likely limited to the most difficult cases.

In our opinion, such a procedure should be based on moral suasion rather than binding rules, which could not be issued without a rather long and demanding EU legislative process. Further, it may be too early for binding rules, as a voluntary approach may be tried first.

The procedure would envisage a streamlined decision process, centred on a Project Conference (PC).

The suggested PC is meant to:

- Streamline cooperation and procedures (to deal in particular with any regulatory cross-border issues);
- Promote public commitment on the application of regulatory incentives;
- Increase transparency and public participation.

The Project Conference (PC) should not be a decision-making body, or an instrument to bypass already existing institutions, such as ACER. It should not create another layer of bureaucracy and should be fast and simple, avoiding further delays to the investment being commissioned. Since no proper design/procedure to tackle cross border issues is in place yet, the PC would help in this direction, as a way of implementing Article 5.3 of the TEN-E regulation, which suggests that "The Groups may... convene meetings with the relevant parties and invite the Commission to verify the information provided on site".

For each PCI, at the request of (qualified) stakeholder(s), the Project Conference should be swiftly organised by the concerned NRAs. Deadlines for the call, preparation and implementation of the Project Conference should be set in advance and contained within a short time (e.g. two to three months).

The PC could have the format of a hearing organised by concerned NRAs, co-ordinated by ACER. The relevant roles of ACER and NRAs in the preparation and running of Project Conferences also depends on staff availability.

Invitations should be extended to all PCI stakeholders including for example: project promoters, prospective investors and lenders, TSOs, ENTSOs, prospective infrastructure users or their associations, market operators, Member States, NGOs representing end consumers or environmental concerns, local government representatives or their associations. NRAs have expressed the fear that such an event could make the process rather “complex, time-consuming and burdensome”. On the other hand, stalemates in large investment decisions are most often triggered by a lack of transparency, which create suspicion amongst stakeholders who feel excluded and may resort to other, more vocal actions (like lawsuits, public campaigns, demonstrations) which in turn may block the processes by frightening project promoters and investors.

Thus, in spite of the potentially large audience, a Project Conference might be a reasonable tool to overcome issues which would not unravel otherwise. A PC should be preferred to not having anything, even if downsides and risks exist given the involvement of several stakeholders. On the other hand, whereas access to stakeholders could not be denied, it should be made clear that the PC focuses on economic risk and related mitigation. It should not be confused with any meeting designed to discuss (e.g.) the
environmental impact of Projects. In this way, the PC is not likely to attract large audiences. It would be limited to stakeholders who have a good familiarity with the relevant regulatory systems and which give suggestions on how to improve them.

On the other hand, there is no reason to organize such events if the PCI evolution is smooth and promoters feel that the regulatory framework is adequate, or if they feel that the project problems cannot be solved by regulators. Thus, the PC should by no means be launched for all PCIs.

Since the purpose of the PC is to discuss the regulatory framework, the right to call them should be awarded to NRAs, Member States, TSOs, Regional Groups and the European Commission. The basis for the request, to be addressed to concerned NRAs or to ACER, should be the Reports required by Article 5.4, wherever the PCI development is regarded as unsatisfactory.

Thus, the event could in practice be similar to the Stakeholders’ Meetings of Regional Initiatives, but it would be more focused and narrower in scope. It could be preceded by the issuance of consultation papers describing the project, assessing their risks and analysing their current mitigation towards the benchmark provided by the best practices, which have been described in chapter 4. Yet, if enough information is already available, it could simply be proposed as the basis for the PC, to avoid further burdens.

If necessary for the purpose of discussing confidential data, project promoters and investors may have separate meetings with the relevant NRAs.

The Project Conference would:

- Take stock of all positions, and
- By consensus, set deadlines for joint decisions by concerned NRAs. Such decisions could include:
  - The assessment of the level of risk of PCIs
  - The adoption of measures, if necessary representing best practices for risk mitigation in the relevant case (in additional to those already in place in the relevant regulatory framework) and tailored to the specific case or (cross border) context of the PCI.

CBCA decisions shall not be addressed by the PC as a legal instrument already exists to deal with it. The regulatory framework should however be assessed only after the CBCA has been defined, as no proper assessment is possible without the CBCA. On the other hand, the evaluation of project risks and the definition of additional incentives (if any) should take place early in the investment decision process, just after the CBCA decision. This timing aims to enhance the stability of the regulatory system, which is of high importance to project promoters; but also to avoid strategic behaviour by project promoters who could commit fewer resources in order to trigger better incentives. Moreover, early decisions on incentives would avoid the perception (even though it is wrong) that some “bargaining” occurs between project promoters and regulators.

In any case, the decision making would be left to the NRAs, by consensus.

In addition, we recommend that concerned Member States, TSOs or the European Commission could ask for reconsideration of the decisions, including those on the
granting or denial of a preferential regulatory treatment. The ACER Recommendation does not foresee this possibility\textsuperscript{89}.

Such reconsideration could be carried out by neutral, independent experts, following the model of the International Chamber of Commerce (ICC) arbitrations, where recommendations are issued by a Committee of Arbitrators\textsuperscript{90}. The Arbitrators could be designated by ACER or drawn among experts designated by NRAs that are not involved in the relevant PCI or in any other PCIs that may be seen as having a direct or indirect interest in the promotion of the PCI\textsuperscript{91}.

The Experts would give their opinion on higher PCI risks and their mitigation and promote the spreading of best practices. While primarily addressed to NRAs, their recommendations could also ask Member States or other authorities to intervene, for example to promote longer regulatory periods or guarantees for investment beyond the mandate of regulators, or to lift provisions that hamper the implementation of Best Practices. In a sense, the role of this Committee would resemble (on regulatory matters) that of the European Coordinators established by article 6 of the TEN-E Regulation.

Such opinion, however, would not have legally-binding consequences. In fact, the Committee would issue a non-binding recommendation. However, the Committee's opinion may weigh on the official Appeals procedures that are generally foreseen by Member States. These are rather different and not harmonised, as they are related to their own, different legal systems. Hence the legal impact of such opinions may differ, but it is likely to be significant in many countries;

If systematic delays keep happening, the European Commission would have a basis to intervene, requiring a proper implementation of Article 13, based on its general powers. This could occur by turning the Guidelines into a legal instrument, possibly foreseeing a single body with the power to introduce incentives where necessary. However, since in most cases PCIs are expected to proceed anyway and risk mitigation is already regarded as satisfactory, this “last resort” option is likely to occur only in very limited cases. The Experts’ opinion is actually likely to strengthen the NRA’s, as they would provide a more independent opinion, expressed by regulatory experts who are not directly involved in the controversies\textsuperscript{92}. In order to speed up the process, it may be foreseen that experts are appointed whenever a PC is called, and attend it so that they are ready to provide an opinion if necessary.

5.4.2. Guidance on incentive design

As mentioned before, two broad categories of project risks can be distinguished:

- Risks related to the (technical) characteristics of PCIs, so-called project-specific risks; and

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\textsuperscript{89} The procedure foreseen by Article 8 of Regulation 713/2009/EC does not seem to apply as it refers to existing infrastructure, and it is also relatively slow. However this point may require further legal advice.

\textsuperscript{90} This is without prejudice to the non binding nature of the Arbitrators’ decisions, which may differ in that from the ICC practice.

\textsuperscript{91} For example, involvement of NRAs whose constituencies may host a competing project of the PCI at issue should be excluded.

\textsuperscript{92} A somehow similar role of external, independent experts is played by European coordinators, foreseen by Article 6 of the TEN-E Regulation.
• Risks related to the institutional setting of PCIs, so-called systemic risks.

Project-specific risks are for example related to the technical lifetime of the infrastructure’s components, the time-out-of-use during the investment’s lifetime, and the uncertainty during the construction phase about the investment going to be commissioned at all. Systemic risks are for example related to adverse legislation, adverse regulatory decisions, and failure in coordinating major investments resulting in excess capacity and stranded assets.

We first focus on minimizing systemic risks. A well-known example of a regulatory incentive or measure that reduces systemic risks is the use of the Ten-Year Network Development Plan (TYNDP) – and underlying national and regional investment plans – since 2010 to achieve a timely and well-planned development of energy network infrastructure in the EU. By identifying gaps in infrastructure from a European perspective and informing stakeholders on major investment projects, the TYNDP contributes to an EU-wide consistent and transparent investment planning process. The TYNDP thereby reduces the risk that infrastructure investments turn out to be redundant after they have been commissioned.

Reducing systemic risks is not limited to a regulatory context. Dealing with intergovernmental cooperation in the energy sector, the 1994 Energy Charter Treaty is an example of a policy measure that reduces systematic risks. The Treaty provides a multilateral legal framework aiming to strengthen the rule of law on energy issues, thereby minimizing the risks associated with energy-related investments and trade. The Treaty focuses on the protection and promotion of foreign energy investments; free trade in energy materials, products and energy-related equipment; freedom of energy transit through pipelines and grids; improving energy efficiency; and mechanisms for the resolution of state-to-state or investor-to-state disputes. Policy risk may however still be perceived as high in several Member States. Consider for instance the 2013 reform of renewable energy remuneration system in Spain, which led the Spanish energy sector to take severe losses on previous investments in terms of missed subsidies and guaranteed revenues.

As already mentioned, we do not recommend the harmonisation of one or more regulatory instruments across the entire EU. Yet, we found that there is general agreement, across all stakeholder groups, that minimizing systemic risk by providing stability provisions is one of the two most necessary regulatory incentives or measures. Consequently, the guidelines should recommend that, when deciding on appropriate incentives for a PCI with a higher risk profile than comparable projects, NRAs should focus on stability provisions. Stability provisions would for instance include: longer regulatory periods, a ban on retroactive decisions, no adverse recalculation of RABs, and/or guaranteed higher returns (if foreseen).

PCIs’ benefits will partly consist of increased security of supply or increased competition in supply and will therefore be based on achieving excess transportation capacity. If merchant investments are supposed to remain viable under these circumstances, then regulatory incentives or measures need to be put in place to ensure that the excess capacity does not reduce the value of the non-excess capacity. Value of Lost Load (VoLL) pricing of strategic reserves in electricity generation is an example of such a measure.

Second, we focus on project-specific risks and their optimal allocation through the applied regulation. Regulatory theory suggests that risks should be carried by project promoters if and only if it is necessary to incentivise them to be efficient. Reason is that risk taking by project promoters has to be compensated and therefore comes at a price to the users of the infrastructure. Regulatory theory also suggests that cost-plus
regulation provides strong incentives for developing new infrastructure; under cost-plus regulation the rate of return on the asset base is guaranteed and the risk faced by the regulated firm is therefore significantly reduced. Price-cap regulation may weaken the incentive to invest in new infrastructure, for instance due to regulatory opportunism when regulatory periods are shorter than the assets’ lifetimes.93

Based on these considerations PCIs should generally be regulated in a way that leaves project promoters with relatively little risks. Such an approach will reduce financing costs and encourage investments. Reducing project promoters’ risk could for instance be realised by assigning volume risk to users, regulating innovative projects on a cost-plus basis, or committing to not taking adverse regulatory decisions regarding an investment’s efficiency.

The resulting loss of incentives for project promoters to deliver PCIs efficiently and in time can under such circumstances be pursued in alternative ways: organising tenders to procure the investment’s technology and the party to construct the infrastructure, close monitoring of progress by the NRA, and potentially using incentive schemes on specific targets (for instance the commissioning date).

We have found that there is general agreement, across all stakeholder groups, that the other most necessary regulatory incentive – next to stability provisions – is measures to mitigate liquidity risk. Measures to mitigate liquidity risk are another example of regulating PCIs in such a way that little risk is left with the project promoters. Consequently, the guidelines should recommend that, when deciding on appropriate incentives for a PCI with a higher risk profile than comparable projects, NRAs should particularly focus initially on measures to mitigate liquidity risk. Measures to mitigate the liquidity risk include the early recognition of costs, the inclusion of anticipatory investments, TSO revenues based on scheduled rather than actual capacity or flow measures (possibly subject to correction through regulatory accounts). Moreover, where cash flow problems are more likely to exist, monitoring the investment grading of the involved TSOs and/or using a more favourable depreciation regime may help.

Finally, only if mitigating incentives (like stability provisions and measures to mitigate liquidity risk) are not regarded as sufficient should NRAs apply rewarding incentives like rate of return premiums.

---

ANNEX 1 – STAKEHOLDER QUESTIONNAIRE

In order to obtain stakeholders´ views on regulatory risks for PCIs, a questionnaire was circulated in May 2014. The questionnaire was split into two component parts: the first part was designed to illicit information from respondents related to their views on regulatory risks for PCI investments as well as their opinions on the efficacy and appropriateness of different regulatory incentives to address risks. The second part was concerned with any perceived currently-occurring delays or cancellations to PCIs. In total, 26 questionnaire responses were received: 14 from TSOs; 9 from NRAs; and 3 from investors.

A copy of the stakeholder questionnaire used within this assignment is provided below for reference.

Section A. General View.

1. Which factors do represent risks for Projects of Common Interest (PCI) implementation in your opinion?

<table>
<thead>
<tr>
<th>Factor</th>
<th>Not at all</th>
<th>Limited</th>
<th>Serious</th>
<th>Overwhelming</th>
</tr>
</thead>
<tbody>
<tr>
<td>Time overrun</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Unrecovered cost overrun</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Cross-border coordination issues</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Cash flow difficulties</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Financing issues</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Market risk</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Future adverse regulatory decisions</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
2. **How should risk be assessed for PCIs?**

<table>
<thead>
<tr>
<th>option</th>
<th>Yes</th>
<th>No</th>
<th>Don’t know</th>
</tr>
</thead>
<tbody>
<tr>
<td>At company level only</td>
<td>☐</td>
<td>☐</td>
<td>☐</td>
</tr>
<tr>
<td>Risk assessment should be embedded into Cost-Benefit Analysis</td>
<td>☐</td>
<td>☐</td>
<td>☐</td>
</tr>
<tr>
<td>By means of a “matrix of risks” developed at EU level</td>
<td>☐</td>
<td>☐</td>
<td>☐</td>
</tr>
<tr>
<td>Case specific assessment of risk mitigation</td>
<td>☐</td>
<td>☐</td>
<td>☐</td>
</tr>
<tr>
<td>Other (……………………………………………………………………………………….)</td>
<td>☐</td>
<td>☐</td>
<td>☐</td>
</tr>
</tbody>
</table>

3. **How can risks be more effectively mitigated?**

<table>
<thead>
<tr>
<th>option</th>
<th>Not necessary</th>
<th>Useful</th>
<th>Necessary</th>
</tr>
</thead>
<tbody>
<tr>
<td>Higher rate of return / WACC premiums</td>
<td>☐</td>
<td>☐</td>
<td>☐</td>
</tr>
<tr>
<td>Early recognition of costs</td>
<td>☐</td>
<td>☐</td>
<td>☐</td>
</tr>
<tr>
<td>Anticipatory investment</td>
<td>☐</td>
<td>☐</td>
<td>☐</td>
</tr>
</tbody>
</table>
Longer regulatory period, stability provisions

Adjusted depreciation period

Other (…………………………………..…)

Please add any additional comments/explanation for your answer if you wish

…………………………………………………………………………………….

…………………………………………………………………………………….

Section B. Case-specific View

Are you aware of a PCI (or other similar cross-border Project) that is at risk of failure or delay due to inadequate regulatory treatment? If yes, please identify the Project.

…………………………………………………………………………………………………..

Is this Project being seriously delayed ☐ or cancelled ☐ ? (Please tick as appropriate)

1. Which risk factors in your view are affecting the implementation of this Project?

94 Please refer to PCI list if appropriate. If you want to mention more than one Project, please duplicate this section.
2. How could risks be more effectively mitigated for this Project?

<table>
<thead>
<tr>
<th>Risk Category</th>
<th>Not at all</th>
<th>Limited</th>
<th>Serious</th>
<th>Overwhelming</th>
</tr>
</thead>
<tbody>
<tr>
<td>Time overrun</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Unrecovered Cost overrun</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Cross-border coordination issues</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Cash flow problems</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Financing issues</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Market risk</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Other (………………………………)</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Higher rate of return / WACC premiums

Early recognition of costs, anticipatory investment
### Longer regulatory period, stability provisions

- [ ]
- [ ]
- [ ]

### Adjusted depreciation

- [ ]
- [ ]
- [ ]

### Other (…………………………………..…)

- [ ]
- [ ]

Please add any additional comments/explanation for your answer if you wish

```
…………………………………………………………………………………….
```

```
…………………………………………………………………………………….
```
MAIN DEFINITIONS

As some of the terms used in the Questionnaire may not have an agreed definition, please consider the following definitions, which are used by ACER:

**Anticipatory Investment**: Investments in assets that may need to be made before demand for the assets’ services exists, for example constructing a pipeline of a certain maximum capacity before reaching the expected production level from a gas field. There is a risk of "stranded assets" if investments are made in assets which are not used because the demand for their services does not develop as expected.

**Cash flow problems**: Inadequate stream of revenues after the investment decision, threatening the promoters’ economic viability in carrying out the project.

**Early recognition of costs**: Inclusion of assets values into the RAB and/or of their related operational costs into the OPEX before the new asset is commissioned. May be subject to refund if the asset is not commissioned.

**Financial issues**: difficulties in persuading financial partners to agree an appropriate financing conditions for the Project.

**Market risk**: risk that demand for the services of the assets developed by the Project may results inadequate and the missing is not covered by the regulated tariffs or other sources.

**Stability provisions**: Provisions of regulatory decisions ensuring that certain regulatory conditions are extended beyond the current regulatory period.
### ANNEX 2 – SENSITIVITY ANALYSIS, RATE OF RETURN CALCULATION AND INVESTMENT COST EVALUATION IN MEMBER STATES

Analysis of the NRAs’ submissions, electricity projects

<table>
<thead>
<tr>
<th>Member State</th>
<th>Does the NRA formally require any risk or sensitivity analysis of proposed investments?</th>
<th>How is the rate of return calculated for the TSO(s)?</th>
<th>Are standard costs or benchmarking methods used for investment cost evaluation?</th>
</tr>
</thead>
<tbody>
<tr>
<td>Austria</td>
<td>Yes</td>
<td>CAPM</td>
<td>Planned</td>
</tr>
<tr>
<td>Belgium</td>
<td>NA</td>
<td>CAPM</td>
<td>NA</td>
</tr>
<tr>
<td>Bulgaria</td>
<td>No</td>
<td>NA</td>
<td>NA</td>
</tr>
<tr>
<td>Croatia</td>
<td>Planned</td>
<td>CAPM</td>
<td>NA</td>
</tr>
<tr>
<td>Cyprus</td>
<td>Planned</td>
<td>Cost plus</td>
<td>NA</td>
</tr>
<tr>
<td>Czech Republic</td>
<td>No</td>
<td>CAPM</td>
<td>NA</td>
</tr>
<tr>
<td>Denmark</td>
<td>No</td>
<td>Cost plus</td>
<td>NA</td>
</tr>
<tr>
<td>Estonia</td>
<td>No</td>
<td>Cost plus</td>
<td>Yes</td>
</tr>
<tr>
<td>Finland</td>
<td>No</td>
<td>CAPM</td>
<td>Yes</td>
</tr>
<tr>
<td>France</td>
<td>No</td>
<td>CAPM</td>
<td>NA</td>
</tr>
<tr>
<td>Germany</td>
<td>No</td>
<td>CAPM(^{96})</td>
<td>NA</td>
</tr>
<tr>
<td>Greece</td>
<td>Yes</td>
<td>Cost plus</td>
<td>NA</td>
</tr>
<tr>
<td>Hungary</td>
<td>No</td>
<td>CAPM</td>
<td>NA</td>
</tr>
<tr>
<td>Ireland</td>
<td>Yes, for interconnector</td>
<td>CAPM</td>
<td>NA</td>
</tr>
<tr>
<td>Italy</td>
<td>No</td>
<td>CAPM</td>
<td>NA</td>
</tr>
<tr>
<td>Latvia</td>
<td>Planned</td>
<td>Cost plus</td>
<td>NA</td>
</tr>
</tbody>
</table>

\(^{95}\) (NRAs that do not explicitly mention use of benchmarking or standard cost techniques are reported in the Table as “NA”, as no explicit question was formulated in the Questionnaire. Therefore it is likely that more NRAs may use similar approaches but have not reported them in their answers).

\(^{96}\) The CAPM and the return on equity is for all companies the same. However, the overall rate of return is different for each company because the actual cost of debt and the actual capital structure for each company is taken into account.
Analysis of the NRAs’ submissions, gas projects

<table>
<thead>
<tr>
<th>Member State</th>
<th>Does the NRA formally require any risk or sensitivity analysis of proposed investments?</th>
<th>How is the rate of return calculated for the TSO(s)?</th>
<th>Are standard costs or benchmarking methods used for investment cost evaluation?</th>
</tr>
</thead>
<tbody>
<tr>
<td>Austria</td>
<td>Yes</td>
<td>CAPM</td>
<td>Planned</td>
</tr>
<tr>
<td>Belgium</td>
<td>No</td>
<td>CAPM + Financial embedded debt principle</td>
<td>NA</td>
</tr>
</tbody>
</table>

97 (NRAs that do not explicitly mention use of benchmarking or standard cost techniques are reported in the Table as “NA”, as no explicit question was formulated in the Questionnaire. Therefore it is likely that more NRAs may use similar approaches but have not reported them in their answers).
<table>
<thead>
<tr>
<th>Country</th>
<th>Does the NRA formally require any risk or sensitivity analysis of proposed investments?</th>
<th>How is the rate of return calculated for the TSO(s)?</th>
<th>Are standard costs or benchmarking methods used for investment cost evaluation?</th>
</tr>
</thead>
<tbody>
<tr>
<td>Bulgaria</td>
<td>NA</td>
<td>NA</td>
<td>NA</td>
</tr>
<tr>
<td>Croatia</td>
<td>Planned</td>
<td>Cost plus</td>
<td>For OPEX formally provided but not implemented yet</td>
</tr>
<tr>
<td>Cyprus</td>
<td>NA</td>
<td>NA</td>
<td>NA</td>
</tr>
<tr>
<td>Czech Rep.</td>
<td>No</td>
<td>CAPM</td>
<td>Benchmarking only as supplementary method</td>
</tr>
<tr>
<td>Denmark</td>
<td>No</td>
<td>Cost plus</td>
<td>NA</td>
</tr>
<tr>
<td>Estonia</td>
<td>NA</td>
<td>NA</td>
<td>NA</td>
</tr>
<tr>
<td>Finland</td>
<td>NA</td>
<td>CAPM</td>
<td>Yes, benchmarking against TSO own historical costs</td>
</tr>
<tr>
<td>France</td>
<td>No</td>
<td>CAPM</td>
<td>NA</td>
</tr>
<tr>
<td>Germany</td>
<td>No</td>
<td>CAPM</td>
<td>Yes, ex post TOTEX-benchmarking</td>
</tr>
<tr>
<td>Greece</td>
<td>NA</td>
<td>Cost plus</td>
<td>NA</td>
</tr>
<tr>
<td>Hungary</td>
<td>NA</td>
<td>CAPM</td>
<td>Costs are compared to those of similar investments</td>
</tr>
<tr>
<td>Northern Ireland</td>
<td>No</td>
<td>CAPM</td>
<td>Planned</td>
</tr>
<tr>
<td>Italy</td>
<td>No</td>
<td>CAPM</td>
<td>NA</td>
</tr>
<tr>
<td>Latvia</td>
<td>Planned</td>
<td>Cost plus</td>
<td>No</td>
</tr>
<tr>
<td>Lithuania</td>
<td>Yes</td>
<td>CAPM</td>
<td>NA</td>
</tr>
<tr>
<td>Luxembourg</td>
<td>No</td>
<td>CAPM</td>
<td>NA</td>
</tr>
<tr>
<td>Malta</td>
<td>No</td>
<td>Cost plus (WACC may be used in future)</td>
<td>NA</td>
</tr>
<tr>
<td>The Netherlands</td>
<td>No</td>
<td>CAPM</td>
<td>No</td>
</tr>
<tr>
<td>Norway</td>
<td>No</td>
<td>CAPM</td>
<td>Yes</td>
</tr>
<tr>
<td>Poland</td>
<td>No</td>
<td>CAPM</td>
<td>No</td>
</tr>
<tr>
<td>Portugal</td>
<td>NA</td>
<td>CAPM</td>
<td>NA</td>
</tr>
<tr>
<td>Country</td>
<td>Does the NRA formally require any risk or sensitivity analysis of proposed investments?</td>
<td>How is the rate of return calculated for the TSO(s)?</td>
<td>Are standard costs or benchmarking methods used for investment cost evaluation?</td>
</tr>
<tr>
<td>------------</td>
<td>--------------------------------------------------------------------------------------</td>
<td>--------------------------------------------------</td>
<td>----------------------------------------------------------------------------------</td>
</tr>
<tr>
<td>Romania</td>
<td>Yes</td>
<td>CAPM</td>
<td>Only in one case</td>
</tr>
<tr>
<td>Slovakia</td>
<td>In preparation</td>
<td>CAPM</td>
<td>NA</td>
</tr>
<tr>
<td>Slovenia</td>
<td>No</td>
<td>CAPM</td>
<td>OPEX only</td>
</tr>
<tr>
<td>Spain</td>
<td>No</td>
<td>CAPM</td>
<td>Yes</td>
</tr>
<tr>
<td>Sweden</td>
<td>No</td>
<td>CAPM</td>
<td>NA</td>
</tr>
<tr>
<td>The UK</td>
<td>No</td>
<td>CAPM</td>
<td>Yes</td>
</tr>
</tbody>
</table>
ANNEX 3 - EXPERIENCES WITH REGULATORY INCENTIVES OUTSIDE THE EU

This section describes the recent relevant experience of non-EU countries with the use of regulatory incentives for investments in energy sector infrastructure.

UNITED STATES

In the United States, investments in power sector infrastructure are regulated at both the federal and state levels, by the Federal Energy Regulatory Commission (FERC) and state-specific regulatory authorities, respectively. At the federal level, a major change was implemented in 2005 and 2006 in the regulatory approach used to incentivize investments in key power sector infrastructure.

In 2005 the United States Congress, through the Energy Policy Act 2005, directed FERC to develop incentive transmission investment rules which were more robust, flexible and ultimately, more attractive for would-be investors. FERC implemented section 219 of the Federal Power Act by issuing Order Nos. 679 and 679-A concerning incentive-based rate treatment for investment in electricity transmission infrastructure. The objective of the amendment was twofold:

1. To provide incentives for the realization of investments which would help to ensure the reliability of the bulk transmission system in the United States; and
2. To reduce the cost of electricity delivered to consumers by reducing congestion on transmission infrastructure.

The changes in the regulatory incentives served to provide greater regulatory certainty and procedural flexibility (with respect to the nature and timing of rate of recovery) for major infrastructure projects. The newly-introduced incentives represented a departure from the previous approach, wherein FERC had only allowed higher rates of return and adjustments to typically-used ratemaking practices within a very limited number of isolated transmission infrastructure investments.

Regulatory Incentives

The United States’ regulatory incentives system can be considered as including a broad spectrum of investment incentives, from which the regulator can justify permission (or not) of the use of specific incentives, on an individual investment basis.

Section 219 of the Energy Policy Act 2005 made provisions for the potential use of a suite of investment incentives, specifically:

- Full recovery of reasonable Construction Work in Progress Costs;
- Full recovery of reasonable pre-operations costs;
- Full recovery of reasonably-incurred costs of facilities which are abandoned;
- Incentive rates of return on equity for new investment by public utilities (including both traditional utilities and stand-alone transmission companies);
• Use of hypothetical capital structures; that is, the use of standardized costs, as opposed to actual company costs;
• Accelerated depreciation periods;
• Accumulated deferred income taxes for transmission companies;
• Adjustments to the book value of transmission companies resulting from sales and purchases;
• Deferred cost recovery arrangements for utilities which have implemented a freeze on their retail rates; and
• Higher rates of return on equity for utilities which either join or continue to be members of transmission organizations. Such organizations include, amongst others, independent system operators and regional transmission organizations.

The allowed rates of return for project promoters are subject to Federal Power Act rate filing standards. Utilities investing in infrastructure are permitted to select, suggest and justify the package of incentives that they consider to be necessary to support investments, on a case-by-case basis. The particular package of measures is then discussed and agreed with FERC.

**Rationale for introducing the incentives**

When the above-described regulatory incentives for power sector infrastructure investments were introduced by FERC IN 2006, a range of impacts on the investment landscape were anticipated, including:

• Membership of Regional Transmission Organizations would be encouraged and membership levels would increase;
• The risks associated with the use of new and innovative technologies would be offset;
• The risks associated and taken on by single asset entities would be offset;
• Investments in critical and essential transmission asset infrastructures would be encouraged and realized in a timely way;
• Planned power line investments could be realized in a more timely way, primarily due to it being harder for public interest and/or environmental groups to delay the approval of projects at the state level. This is because power line investments could be classified as being of national interest: with the effect that the federal level government (not state-level) would administer investment approvals;\(^98\)
• The provision of higher rates of return on investments was not, in itself, anticipated to lead to more investments in transmission infrastructures; but in combination

with other incentive aspects it was considered that the profile of investments would be raised sufficiently to ensure that investments were realized.

Regulatory incentives’ impacts

The impact of the newly-introduced regulatory incentive mechanisms was to support the development of various investments, primarily through enhancing the allowed rate of returns for projects. Some examples of specific investments which obtained enhanced rate approvals are shown in Figure 10.

Figure 10: Rate of return approvals of various projects

<table>
<thead>
<tr>
<th>Investment</th>
<th>Allowed ROE</th>
<th>Incentives adders allowed</th>
<th>Total (final) ROE</th>
</tr>
</thead>
<tbody>
<tr>
<td>Bangor Hydroelectric Co. (2005) – 111</td>
<td>10.2</td>
<td>100 basis point incentive ROE adder for transmission projects. Approval provided through ISO New England Regional Transmission Expansion Planning process</td>
<td>11.2</td>
</tr>
<tr>
<td>FERC; 63,048</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Northern Pass Transmission LLC (2011) – 134</td>
<td>10.4</td>
<td>166 basis point incentive ROE adder, provided in relation to the unique characteristics of the transmission project and the unique commercial arrangements related to the project construction. 50 basis point incentive ROE adder provided in compensation for involvement in ISO New England Regional Transmission Expansion Planning process</td>
<td>12.56</td>
</tr>
<tr>
<td>FERC; 61,095</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>RITELine Illinois LLC (2011) – 137</td>
<td>9.93</td>
<td>100 basis points added in reflection of the challenges and risks of the project. 50 basis point adder on the basis of involvement in the Regional Transmission Organisation.</td>
<td>11.43</td>
</tr>
<tr>
<td>FERC; 61,039</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Green Power Express LP (2011) – 135</td>
<td>10.78</td>
<td>10 basis point incentive adder in recognition of the size, scope, risks, challenges and benefits of the investment. 50 basis point adder in compensation of the organisation’s participation in the Regional Transmission Organisation. 100 basis point adder to reflect Green Power Express’ as being an independent transmission-only company.</td>
<td>12.38</td>
</tr>
<tr>
<td>FERC; 61,141</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Atlantic Grid Operations A LLC (2011) – 135</td>
<td>10.09</td>
<td>100 base point adder in reflection of the complexity and risks involved with the project. 50 base point adder in return for using advanced technologies. 50 base point adder for project developer’s status as a Transco. 50 base point adder due to the company’s participation in the Regional Transmission Organisation.</td>
<td>12.59</td>
</tr>
<tr>
<td>FERC; 61,144</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Virginia Electric and Power Co. (2008) – 124</td>
<td>11.4</td>
<td>150 basis point adder on ROE in reflection of the challenges and risks incurred in four new projects</td>
<td>12.9</td>
</tr>
<tr>
<td>FERC; 61,207</td>
<td></td>
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</tbody>
</table>


99 NERA Consulting, FERC´s U-turn on transmission rate incentives, 2013.
A further example of a project investment which benefited through receiving FERC-approved incentives was the Otter Tail Power Company’s investments in three transmission projects which formed part of the first phase of the CapX2020 Project, in December 2009. That investment received the following incentives:

- 100% of prudently-incurred Construction Work in Progress costs in the base rate;
- 100% of prudently-incurred costs of transmission facilities which are abandoned or cancelled for reasons beyond the investor’s control;
- Otter Tail Power Company was also permitted to recover its revenue requirement based on the use of a forward-looking formula. FERC accepted these incentive arrangements on the basis of Otter Tail Power Company’s submission of a compliance filing (within 30 days) that provided for specific tariff revisions that were necessary for the full implementation of the requested incentives.

In January 2010, and in a separate investment, FERC approved the company Great River Energy’s request for the approval of certain transmission infrastructure investments on three power transmission projects which are part of Phase 1 of Great River Energy’s CapX2020 project. FERC permitted the following incentives’ use:

- Recovery of 100% of the prudently-incurred Construction Work in Progress in the project revenue rate base;
- 100% of prudently-incurred costs of transmission facilities which are abandoned or cancelled for reasons beyond the investor’s control; and
- A hypothetical capital structure of 20% equity and 80% debt.

**Impact on total transmission infrastructure investment**

Some analysis has been undertaken to try to understand the effect of the above-described investment incentives on transmission infrastructure investments in the United States. In general, it is understood that FERC’s implementation of Order 679 has delivered sustained and significant increases in total investment in electric transmission infrastructure. In that sense, the incentives can be considered as having achieved their primary objective of ensuring the key transmission infrastructure investments were made in a timely way.

Since the introduction of the new investment incentive regime in 2006, there has been considerable variation in the annual number of requests by project developers for special investment incentives, and in the number of FERC orders passed approving incentives, as shown in Figure 11. The number of requests for project incentive approvals (and the number of FERC orders approving incentives) both increased in the period from 2006, then peaked in 2008, before reducing significantly in the following year. 2012 was the first year in which no incentive orders were passed to approve incentive requests.
Figure 11: Annual development of FERC incentive orders and requests for incentives

![Graph showing annual development of FERC incentive orders and requests for incentives from 2006 to 2012.](image)

Source: AF-Mercados EMI & REF-E based on data published by NERA (2013)

The data provided in Figure 12 and Figure 13 show both the recent historical annual levels of investment in transmission infrastructure in the United States, and forecast annual investment for the period 2012 to 2015. The information is based on an investment analysis published by Edison Electric Institute in June 2013.

Figure 12: Actual (2001-2011) and planned (2012-2015) transmission infrastructure investment by shareholder-owned electric utilities

![Graph showing actual and planned transmission infrastructure investment from 2001 to 2015.](image)

Source: AF-Mercados Ref-E based on data published by Edison Electric Institute (2013)\(^{100}\)

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It can be observed that substantial and sustained increases in the annual levels of transmission investment have taken place in the United States; a trend of increased spending that has equaled 12% annually for investor-owned utilities from 2005 to 2012 (FERC, 2012). In 2011, transmission investment was US$ 11,070 million, a level of investment 92% higher than that seen in 2001 (US$ 5,821 million), highlighting the scale of increase in annual transmission investment within a decade.

Investments in the period 2012 to 2015 are forecast to remain significantly higher than the average level in the period 2001 to 2011. However, forecast investment was also anticipated to progressively reduce in each year of the 2013 to 2015 period. The Edison Electric Institute highlights that this fall in forecast annual investment is predicted in part because ‘several major projects recently have been modified, delayed or cancelled.’ It is also important to bear in mind that the investment level in each year is generally shaped by the investment ramp-up period, which for transmission projects is typically up to 10 years. That is, given the amount of time required to plan, obtain permits and licenses and build infrastructure, investment levels in each year are shaped by decisions taken in the up-to-10-year investment ramp-up period prior to the specific investment commissioning year. As a result, Edison Electric Institute suggests that the high levels of forecasted investment predicted for 2015 ‘reflects investment decisions made in response to policies enacted by Congress in EPACT 2005 and appropriate ROEs.

FERC has highlighted that most of the new power lines which became operational in 2012 were located in south-central and western states of the country, and some of them received FERC-approved incentives to allow them to obtain higher rates of return on investment. Furthermore, the projects that came on-stream in 2012 were ‘notable because of their scope and importance to the markets. They represent large, high-voltage projects that span substantial distances and required parties to work together for planning and construction. Transmission investments which became operational in 2012 also are notable for their role in transporting power generated from renewable technologies from rural areas to urban load centers and for their foreseen role in improving the reliability of the transmission system.

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Further evolution of FERC’s use of regulatory incentives

In 2012 FERC released a Policy Statement - Promoting Transmission Investment through Pricing Reform, 141 FERC; 61,129 (2012) – on transmission system investment incentives. The Statement indicated FERC’s wish to move away from the use of incentive returns on equity for transmission investments. It was reasoned that there may be a reduced need for ROE improvers due to the use of mechanisms such as the 100% recovery of Construction Work in Progress Costs and/or abandoned plant costs. Moreover, FERC indicated its wish to receive applications for ROE incentive improvement requests only for estimated costs; in particular, any subsequent expenditures on a project would not be eligible to receive the (extended) incentive ROE$^{102}$.

FERC’s policy statement indicated that the Commission would no longer base its decisions on whether to provide additional investment incentives on the basis of whether a project is routine or non-routine. Instead, project promoters applying for special incentives would be required to demonstrate how a package of requested incentives was specifically-designed to address identified risks and challenges of the proposed project. The Statement then specified that FERC would require promoters requesting incentives to initially look to cover project risks through incentives such as the recovery of 100% of Construction Work in Progress Costs, prior to requesting a higher ROE level for an investment. Thirdly, the Policy Statement stressed that FERC would be obliged to ensure that the impacts of the risk-addressing incentives are accounted for appropriately within its determination of whether an incentive ROE (which is set to address risks and challenges) is warranted. Lastly, FERC will no longer consider requests for a stand-alone ROE on the sole basis that the investment is to make use of ‘advanced technology.’

FERC clarified (through its May 2011 Policy Statement, which came into effect in November 2012) that in order to qualify for a higher ROE incentive level for transmission investments, project promoters would need to comply with four key requirements; specifically, that the applicant should demonstrate that:

1. The project faces risks and challenges which are not yet accounted for in the base ROE, or in applicable risk-inducing incentives;

2. That the project/investment alternatives have or will be considered within a transmission planning (or similar) process;

3. That the applicant is taking the appropriate steps and using the appropriate mechanisms in order to minimize the project risk level during the project development process; and

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$^{102}$ The cost estimate favored is that of the estimated project cost included in the regional planning process.
4. The applicant commits to limiting the application of the ROE incentive to a cost estimate for the project.\(^\text{103}\)

Various transmission investment project promoters are currently negotiating and engaged in legal disputes with FERC concerning the regulatory incentive conditions to be applied for investments in the current context of tightened incentive conditions. One such case relates to the question of the appropriate ROE for an investment, heard by FERC within the proceeding of the ISO, New England Inc. Within the hearing, various ratepayer advocates, regulatory authorities and state attorneys general, alleged that the base ROE previously agreed with FERC on the investment should be lowered to a level of no more than 9.2%. This would imply a reduction of at least 194 basis points. The case was notable in that it was being heard against the background of changed market conditions.\(^\text{104}\)

The transmission owners – ISO New England Inc. – argue that the investment ROE should be maintained at 11.14, on the reasoning of being 10.4% and an upward adjustment of 74 basis points to provide for changes in capital market conditions. In the event of the trial, FERC’s trial staff witness recommended that a 9.66% ROE should be implemented for the project.

AUSTRALIA

In July 2013 the Australian Government implemented various new measures to 'promote private investment for infrastructure projects designated to be of national significance', through Division 415 of the Income Tax Assessment Act 1997.

One of the fiscal measures which came into effect was an infrastructure tax incentive which operates by:

- Uplifting the value of carry forward losses at the 10-year Government bond rate; and

- Exempting carry forward losses and bad debt deductions from the continuity of ownership test.\(^\text{105}\)

A cap has been set of AUS $25 billion for the incentive scheme. The investments which are deemed as being eligible to receive the incentives will be selected based on rules (which are yet to be developed and implemented) or which are otherwise determined on a first come-first served basis.

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The measure aims to address issues associated with the situation that there are often long lead times between when an infrastructure project incurs deductible expenditure in the construction phase and when it earns income in the operational phase. The incentive is intended to prevent the value of losses being eroded over time.

The Government aims to recognize that a project entity may have different owners as it moves from the construction to operational phases of a project. In these cases, losses can be used to offset future earnings and benefit both the original and new investors in the project.

One objective of the measure is to increase the scope of investor categories that develop major infrastructure projects in Australia. Prior to July 2013, submissions to include projects or proposals on the national Infrastructure Priority List came primarily from public sector proponents. This was largely to attract Australian Government funding for State-sponsored projects in the event that those projects were assessed favourably by Infrastructure Australia. However, the range of projects or proposals submitted for inclusion on the Infrastructure Priority List is now anticipated to be wider.  

The incentive is anticipated to have the impact that submissions for inclusion on the Infrastructure Priority List are likely for Australian Government projects where private sector investment is planned to play some role. Projects which are to be developed entirely by private entities are also anticipated to apply for inclusion on the Infrastructure Priority List.

Given that the infrastructure tax incentive to investment was only introduced in July 2013, it is not yet possible to conclusively analyse any impacts that the measure may have had on investment behaviour in the area of Australian infrastructure projects of national significance.

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ANNEX 4 – EXAMPLE OF ASSESSMENT GRID FOR THE REGULATORY FRAMEWORK

A Table like the following one should be filled out by NRAs, TSOs, PCI promoters, and (on a voluntary basis) by other stakeholders, also part of the Monitoring of the PCIs pursuant to Article 5.4 of the TEN-E Regulation. It should be filled out for each PCI.

This is a suggested example. The final Table could be more simple, after suitable consultation, where consulted parties could be asked to select (or delete) the most (least) important items.

In each cell, the party should assess whether the risk typologies on the rows are already / should / should not be addressed by tools of the columns, using the following terminology:

- Not necessary (NN)
- Already implemented (AI)
- Useful (US)
- Necessary (NE)

<table>
<thead>
<tr>
<th>REGULATORY INCENTIVES</th>
<th>Premiums (WACC surcharge)</th>
<th>Rules for anticipatory investments</th>
<th>Adjusted depreciation periods</th>
<th>Exemption from efficiency gain requirements</th>
<th>Sliding scale</th>
<th>Favourable debt/equity ratio in the WACC</th>
<th>Longer regulatory periods</th>
<th>Stability arrangements</th>
<th>Exemptions from benchmarking</th>
<th>Early recognition of costs</th>
</tr>
</thead>
<tbody>
<tr>
<td>Policy and Legal</td>
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<tr>
<td>• Lack of proactive political support</td>
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<td></td>
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<td></td>
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<tr>
<td>• Legal gaps or grey areas and poorly-defined laws</td>
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<tr>
<td>• Uncertainty caused by delays in the transposition of EU law</td>
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<td>• Unpredictability of judiciary rulings</td>
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<td>Planning and permitting</td>
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<tr>
<td>• Highly time-consuming, overly-complex or expensive permit application procedures</td>
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</tbody>
</table>
- Bottleneck at the stage of public consultations
- Local opposition delaying permitting/construction phase (also when public consultations have already ended)

**Regulation**
- Changes in regulation, including direct intervention in cost recovery mechanisms (RAB, WACC etc.) and intervention affecting the load factors of the PCI (e.g. changes in capacity allocation rules)
- Lack of sufficient cost recovery mechanisms
- Insufficient assurance against volume/market risk
- Lack of timely recognition of costs
- Asymmetric treatment of PCIs within different regulatory frameworks

**Finance and capital markets**
- Higher interest rates due to long project lifetime and financing period
- Failure in ensuring adequate investment capital
- Grant funding not included in RAB, thereby reducing the project promoter’s return
- Lack of equilibrium on the balance sheet of the project promoter

**Energy markets**
- Competition with other projects, including PCIs
- Changes in energy markets (e.g. fuel prices, market design, CO2 allowances)
- Uncertain demand forecast due to uncoordinated generation and transmission investment
- Non-harmonised market arrangements between countries
- Biased decision-making process due to bundled interests in generation and transmission assets

**Technology**
<table>
<thead>
<tr>
<th><strong>Equipment failure</strong></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Non-availability of technology or difficult access to technology</strong></td>
<td></td>
</tr>
<tr>
<td><strong>Benchmarking based on non-comparable technologies / projects / conditions</strong></td>
<td></td>
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<tr>
<td><strong>Geographic distribution of costs and benefits</strong></td>
<td></td>
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<tr>
<td><strong>Controversial cross-border cost allocation</strong></td>
<td></td>
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<tr>
<td><strong>Counterparty risks</strong></td>
<td></td>
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<tr>
<td><strong>Asymmetry of resources or/and interests of stakeholders</strong></td>
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<tr>
<td><strong>Other</strong></td>
<td></td>
</tr>
<tr>
<td><strong>Supply chain bottlenecks</strong></td>
<td></td>
</tr>
<tr>
<td><strong>Insufficient human resources of project promoter in terms of number and/or experience and skills of staff</strong></td>
<td></td>
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<tr>
<td><strong>Rise of labour force unit costs as a result of increased demand and squeezed supply</strong></td>
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<tr>
<td><strong>Insufficient quantity and quality of the necessary materials for the development of PCIs</strong></td>
<td></td>
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<tr>
<td><strong>Rise of the unit costs of materials due to relatively high demand and squeezed supply</strong></td>
<td></td>
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<tr>
<td><strong>Extreme environmental conditions disrupting construction operations</strong></td>
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</tr>
</tbody>
</table>
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