Methodologies and parameters used to determine the allowed or target revenue of gas transmission system operators (TSOs)

Final report

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Submitted to ACER by:

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Abbreviations and acronyms

ACER	Agency for the Cooperation of Energy Regulators
CAPM	Capital Asset Pricing Model
CEER	Council of European Energy Regulators
CPI	Consumer Price Index
CRP	Country risk premium
DEA	Data Envelopment Analysis
DMS	Dimson, Marsh and Staunton (of the London Business School)
EC	European Commission
ECA	Economic Consulting Associates
ERP	Equity risk premium
EU	European Union
GAAP	Generally Accepted Accounting Principles
Gas Tariff Network Code	Commission Regulation (EU) 2017/460 establishing a network code on harmonised transmission tariff structures for gas
IFRS	International Financial Reporting Standards
IT	Information Technology
MRP	Market risk premium
NRA	National Regulatory Authority
RAB	Regulatory Asset Base
RFR	Risk-free rate
SCADA	Supervisory Control And Data Acquisition (software control system)
TMR	Total market return
TOR	Terms of reference
TOTEX	Total expenditure
TSO	Transmission System Operator
UK	United Kingdom
UKRN	UK Regulators Network
US(A)	United States (of America)
WACC	Weighted average cost of capital

Executive summary

Introduction

This Report has been prepared by Economic Consulting Associates (ECA) for the Agency for the Cooperation of Energy Regulators (ACER) under the assignment: "**Methodologies and parameters used to determine the allowed or target revenue of transmission system operators**".

In broad terms, the objective of this study is to document and contrast the methodologies used by regulatory authorities across the EU in determining and setting the allowed or target revenues of gas transmission companies. The need for the study arises from the prescriptions of the Commission Regulation (EU) 2017/460 establishing a network code on harmonised transmission tariff structures for gas ('Gas Tariff Network Code'), which stipulates that:

> "*Before 6 April 2019, the Agency shall publish a report on the **methodologies and parameters** used to determine the allowed or target revenue of transmission system operators. The report shall be based on at least the parameters referred to in Article 30(1)(b)(iii).*" (Article 34, emphasis added).
>
> The Article 30(1)(b)(iii) parameters are the following:
>
> *(1) types of assets included in the regulated asset base and their aggregated value*
> *(2) cost of capital and its calculation methodology*
> *(3) capital expenditures, including:*
> *(a) methodologies to determine the initial value of the assets*
> *(b) methodologies to re-evaluate the assets*
> *(c) explanations of the evolution of the value of the assets*
> *(d) depreciation periods and amounts per asset type*
> *(4) operational expenditures*
> *(5) incentive mechanisms and efficiency targets*
> *(6) inflation indices.*

The present study is intended to generate the foundation material needed by ACER to meet the above publishing obligations. Given that numerical information is also covered by the annual publications of the National Regulatory Authorities (NRAs) and transmission system operators (TSOs), this Report has focused mostly on methodological matters (except where numerical information is important for demonstrating different approaches).

This Report contains three parts - the first two cover the theory and issues surrounding the setting of regulated revenues for utility network companies, and the findings regarding current EU regulatory practice, respectively. The third part contains the questionnaire employed to obtain information on current EU regulatory practice preceded by summaries of the responses received and the situation applying for each NRA.

This executive summary focuses on (the main elements of) the first two parts of the Report. Specifically, it:

- reviews (both conceptually and in terms of practice currently applied in the EU) the key aspects of TSO revenue setting, namely the overall revenue control mechanism, the review and setting of expenditures, the regulatory asset base, the cost of capital and other regulatory incentive or adjustment mechanisms
- provides our evaluation of the methodological approaches based on the conceptual framework developed for this purpose.

Overall regulatory framework

Theory and issues

There are three main alternative methodologies to determining revenue requirements that are used widely around the world:

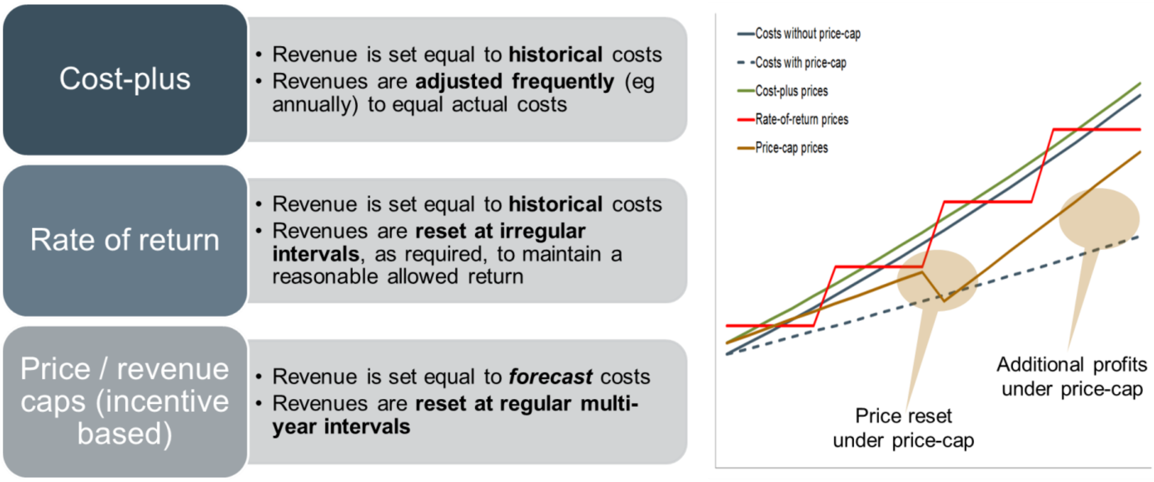
1. **Cash-based methodology**, which focuses on the cash outlays of the regulated entity (including its debt repayments and interest costs).
2. **Accounting methodology**, which relies heavily on setting allowed revenues based on recognised costs under the relevant accounting standards and therefore by mapping revenues to audited financial statements.
3. **Building block methodology** where the revenue requirement is the sum of individual building blocks (that are typically separately assessed and determined *ex ante*), with the costs of making investments recovered through depreciation ('return *of* capital') and return ('return *on* capital') building blocks.

Regardless of the methodology used to establish the revenue requirement, in the absence of revenue adjustments, revenue and costs will inevitably diverge over time. If costs were to rise more than expected, then this could jeopardise the utility's financial position and service to customers. Conversely, if costs were to fall more than expected, then consumers could be paying more than is necessary and the utility earning excess profits. Given those risks and uncertainties, there is a need to adjust revenues to take account of divergences between revenues and costs (having regard also to the incentive impact of any such adjustments).

There are three main regulatory models for adjusting revenue requirements and we summarise these in Figure 1 below[1]. These models are characterisations; in practice, regulators use variants of these models (or use aspects of each in combination) with many additional elements and complexities suited to their context.

[1] In reality, there are more approaches (such as sliding scale and menu regulation), but the three described in the main text seem to capture almost all cases employed worldwide for gas networks.

Figure 1 Main regulatory models for setting and adjusting allowed revenues



Source: ECA (presented at Stakeholder Event in Brussels on 8 February 2018)

Below we highlight some of the key differential features and consequences of the various revenue adjustment models.

Trade-off between efficiency and certain cost recovery

The main trade-off between the three models for adjusting revenues is the balance between the risk to the utility of not recovering its costs and the incentives for productive efficiency.[2]

Incentive regulation provides strong incentives for efficiency, as the utility retains any cost savings it makes during the duration of the price control period, after which the future benefit of these savings is passed on to customers through reduced revenues (see the right-hand panel of Figure 1). The longer the regulatory period, the greater the retained savings and generally the stronger the incentive for efficiency.

In contrast, under rate of return regulation, the divergence between costs and revenues would trigger a review, with the utility only keeping the saving for the time it takes to conduct the review. This 'regulatory lag' means there are some incentives for efficiency under rate of return regulation, but they are muted compared to incentive regulation. In the cost-plus model, where reviews occur annually or more frequently, there is little if any incentive for cost efficiency.

This efficiency incentive, however, involves a trade-off with risk to the utility of not recovering its costs. Under rate of return regulation, if a utility's costs increase, it can seek a review and its revenues will be brought back in line with costs, albeit potentially subject to a slight lag and (potentially) a review to ensure the costs were prudently incurred. In contrast, a utility subject to incentive regulation, must bear cost increases for the duration of the regulatory period. The risk of a utility not recovering its costs is, therefore, greater under incentive regulation. This trade-off is illustrated in the table below.

[2] Productive efficiency is when a product or service is produced at least cost. Allocative efficiency is when products or services sell for their cost (including a normal level of profit).

Table 1 Illustration of risk/reward trade-off under different adjustment mechanisms

Type of adjustments:	Cost of service	Rate of return	Price/revenue cap
Risk that the business will not recover its costs	Low	Medium	High
Incentives for the business to improve efficiency	Low	Medium	High

Trade-off between cost minimisation and quality

Because of the strong cost incentives under incentive regulation, there is a risk that cost reductions will be made at the expense of quality. For this reason, incentive regulation usually includes minimum quality standards, which are intended to mitigate the risk of under-investment. Conversely, the weak incentives for cost efficiency under rate of return regulation means that it can suffer from the opposite problem, with potential incentives for 'gold-plating' investments, although this will likely result in a high quality of service.

Simplicity and transparency

It can also be argued that rate of return regulation is simpler and more objective than price/revenue cap regulation. This is a consequence of rate of return regulation relying on actual, rather than forecast, costs. As they are directly observable, actual costs are more objective than forecast costs, and reviewing actual costs is simpler than reviewing cost forecasts. Consequently, the process for setting a price or revenue cap can be long and involved, requiring significant resources both in the company and in the regulator.

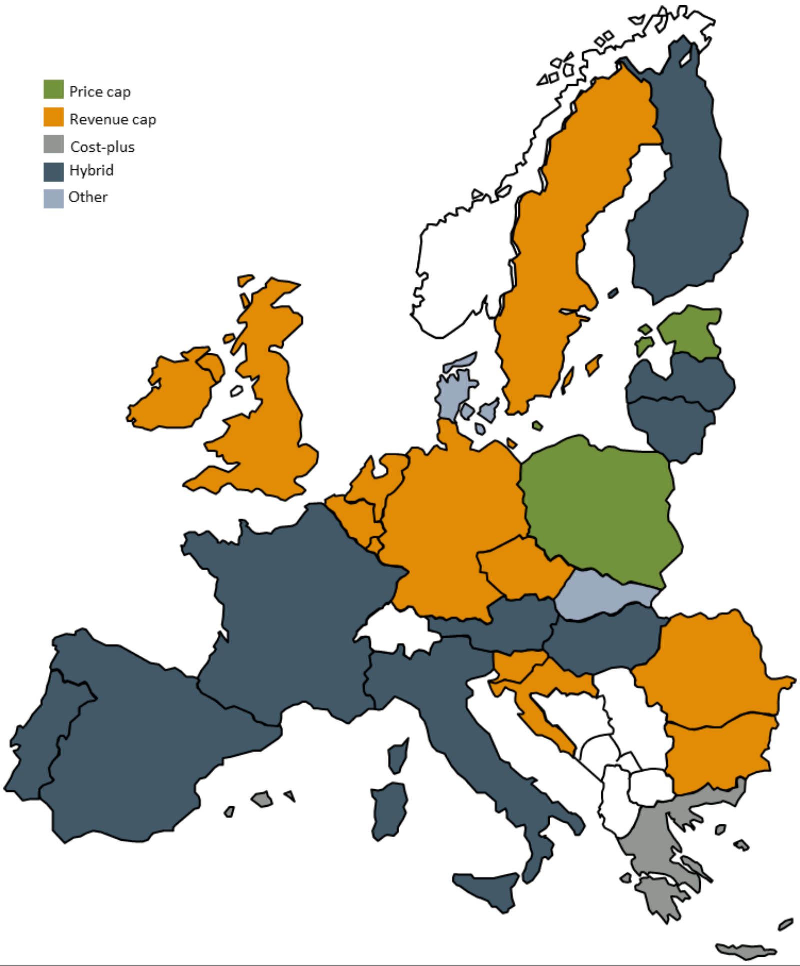
EU regulatory practice

The NRAs were requested to indicate the overall approach used to setting allowed revenues, distinguishing between the following methods:

- A **revenue cap** methodology, where the *revenue* for the TSO is set (that is, tariffs are subsequently adjusted for differences between forecasted and realised volumes to ensure the TSO earns the allowed revenue)
- A **price cap** methodology, where the maximum *tariff level* for the TSO is set by dividing the target revenues by forecasted volumes or capacity (that is, tariffs are not adjusted for differences between forecasted and realised volumes or capacity, and therefore TSO revenues vary with volumes or capacity)
- **Cost-plus and rate of return regulation** where revenue is generally set equal to historical costs and is adjusted to track cost changes or to maintain a reasonable allowed return, respectively
- **Hybrid** approaches entailing some combination of the above
- **Other** approaches that do not fit into the above categorisation and which the NRAs were asked to specify.

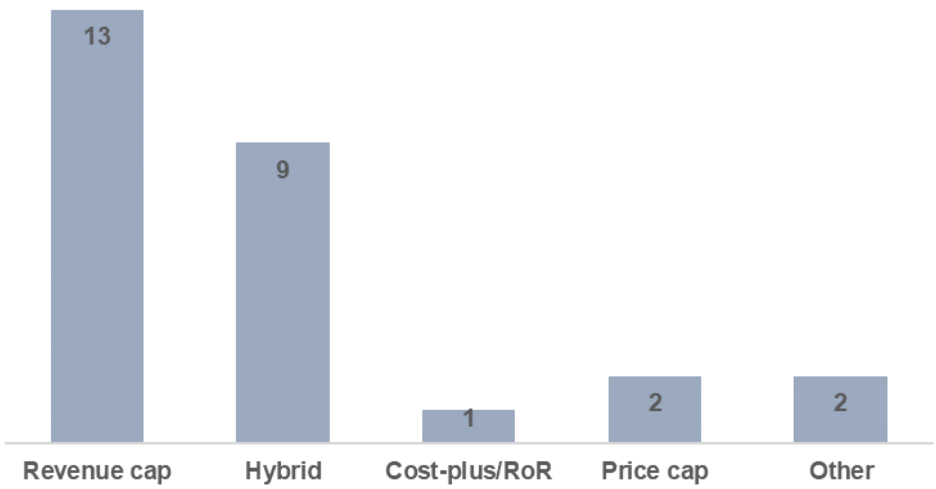
Figure 33 and Figure 34 show the approaches currently being utilised by the various NRAs.

Figure 2 Type of regulation (by country)



Source: NRAs, ECA analysis

Figure 3 Type of regulation (by type and number)



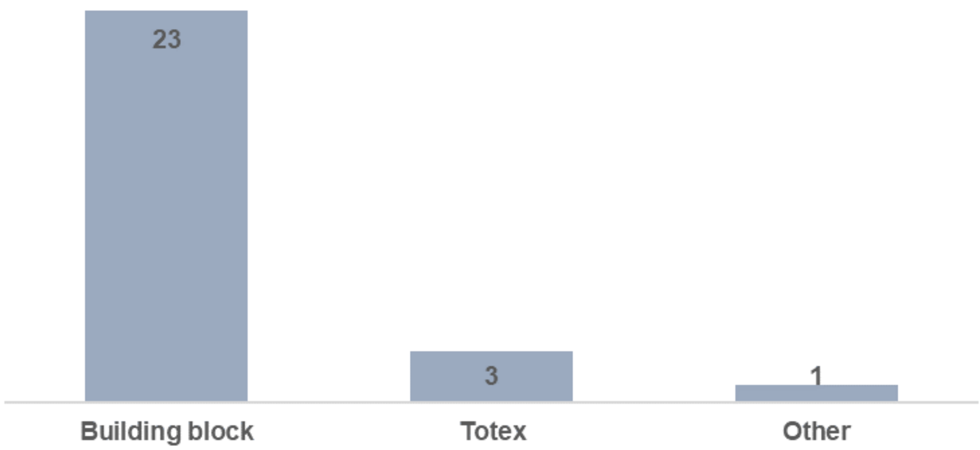
Source: NRAs, ECA analysis

Some key observations from the above figures are the following:

- **Revenue cap is the most common methodology employed**, being used in about half the jurisdictions (13 in total).
- **The next most common approach is a hybrid** – this is employed in nine countries and is almost invariably revenue cap for operating expenditures and cost-plus for capital expenditure.
- **One country employs cost-plus or rate of return regulation, while two countries respectively use price cap regulation and other mechanisms**.

In most cases, irrespective of how allowed or target revenues are 'controlled', NRAs still require some methodology for assessing the cost of service for the TSOs to which the control shall apply. The broad approaches adopted are summarised in Figure 35 below.

Figure 4 Establishing the allowed cost of service (by approach and number)



Source: NRAs, ECA analysis

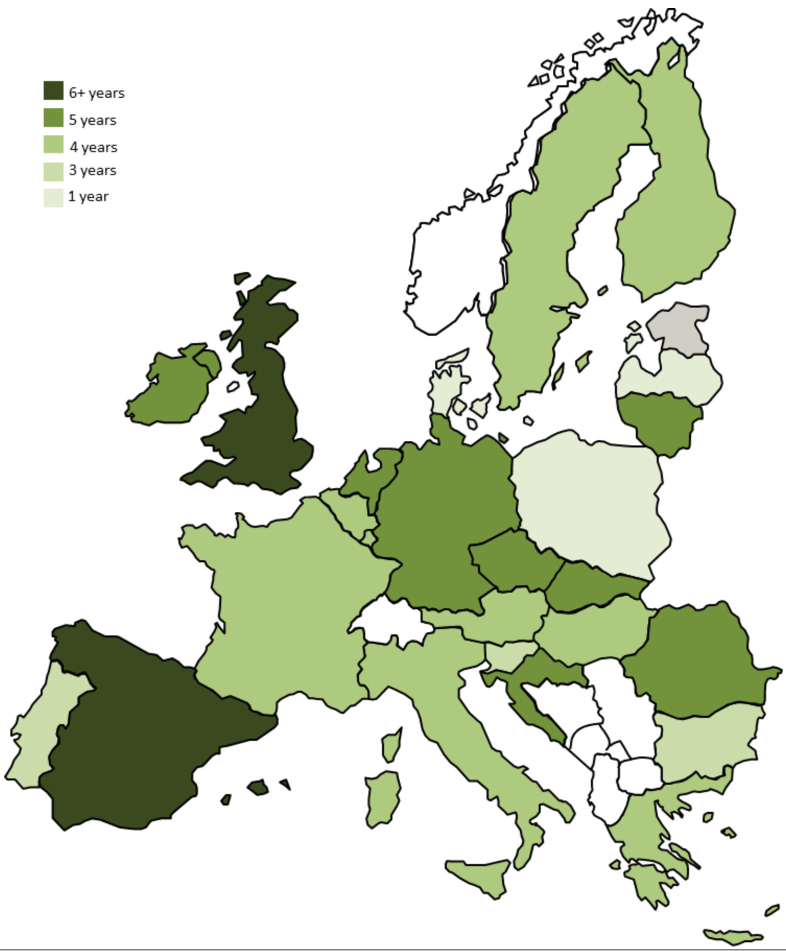
This demonstrates that:

- The **building block approach is used by the vast majority of the NRAs** (23 out of 27), that is, they separately assess all cost components including operating expenditure and capital expenditure
- **A small number employ 'TOTEX' approaches**, where capital and operating expenditures are assessed in combination – this approach is used by three NRAs, specifically, in Germany, the Netherlands and Great Britain
- **One NRA employs neither of the above approaches** – this is Slovakia, where tariff benchmarking is used (ie a comparison of tariffs charged on competing pipelines, which is not to be confused with statistical (cost) benchmarking) for setting the maximum permitted tariffs.

The duration of the regulatory period (being the time for which the allowed or target revenues are initially set, sometimes with predetermined adjustment mechanisms or triggers) varies across the NRAs as shown in Figure 36 and Figure 37 below, although **most**

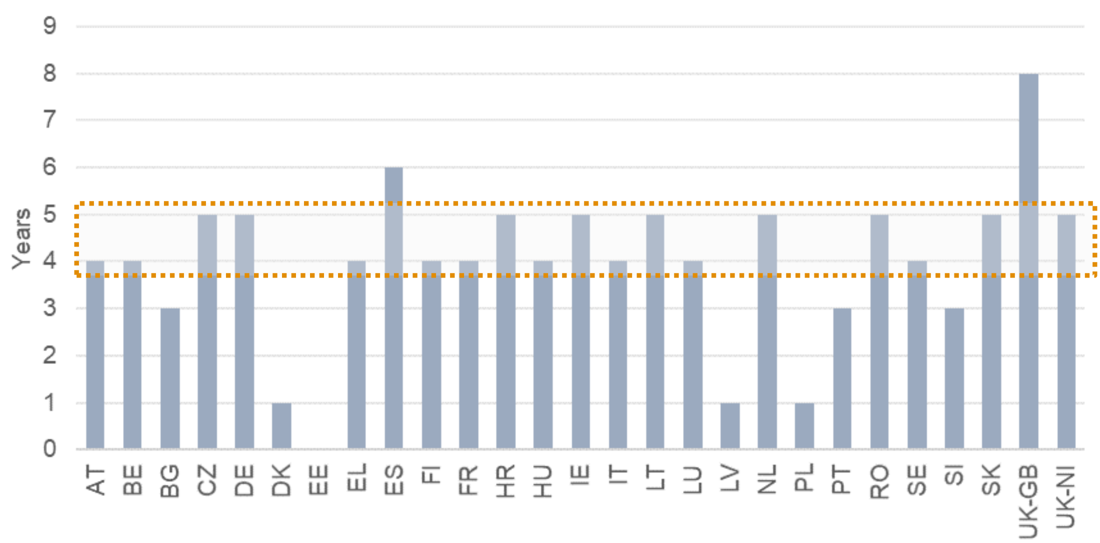
countries have adopted four or five-year regulatory periods (as highlighted by the dotted frame in Figure 37).

Figure 5 Duration of regulatory period (by country)



Source: NRAs, ECA analysis

Figure 6 Duration of regulatory period (years)



Source: NRAs, ECA analysis

Determining and setting expenditure allowances

Theory and issues

Assessing expenditure

There are a wide variety of alternative approaches that regulators internationally take to establishing allowed costs and revenues. These are not mutually exclusive and there are no hard and fast boundaries between them. Different approaches are often combined by regulators. However, we believe it is helpful to simplify this range of options into the following broad categories:

- **Bottom-up assessment** – this looks at the efficiency and reasonableness of individual cost items proposed by the regulated utility. It usually entails separately determining an allowed cost for individual cost lines which are then summed to obtain the total allowed costs.

- **Top-down assessment** – this abstracts from individual cost items and, instead, focuses on broad cost categories. It will tend to make much greater use of evidence from external comparators in assessing the efficiency of proposed costs than is the case under a bottom-up assessment. However, it still retains an element of discretion in setting the final total cost.

- **Yardstick assessment** – this relates allowed costs to an external benchmark, over which the regulated utility has no control. We distinguish such assessment from top-down and bottom-up assessments because these latter use external benchmarks to *inform* decisions on efficient costs but do not *rely* purely on these, in the way that a yardstick assessment does.

It is important to note that a fundamental objective of regulatory regimes is to ensure that **regulated businesses are compensated only for their efficient costs** (and that they be provided with incentives to pursue efficiencies). The concept of efficiency can be decomposed into two components:

- **Relative efficiency ('catch-up')** – this represents the difference between a firm's current level of efficiency and that represented by the most efficient firms now (defined as those firms lying on the 'efficiency frontier')

- **Productivity growth ('frontier shift')** – this represents the expected movement of the efficiency frontier over time. Even the most efficient firms currently will have scope to continue to improve efficiency over time as innovative technologies and work practices become available.

Analytical methods for assessing costs and efficiency

There are several analytical methods employed by regulators (and/or required of the businesses) when assessing (claiming) the reasonableness of forecasted expenditure. The choice of analytical technique generally depends on the nature of the expenditure category being assessed and several methods are used in combination to obtain a holistic view of the total capital and operating expenditure forecasts. Some analytical tools commonly used include:

- **Trend analysis** - this technique entails using trends in historical time series data for specific cost items to detect general patterns and the relationship between associated factors or drivers, and on this basis project the future direction of the pattern (and therefore the relevant costs)

- **Methodology assessment** - some regulators find it important to also understand the analysis underpinning the cost information and specifically, the models used and the related inputs, assumptions and methodologies

- **Detailed project review** - in some cases, regulators might find it necessary to undertake a more detailed review of specific project or programme expenditure

- **Predictive modelling** - this entails the use of statistical and econometric modelling and analytical techniques to determine the expected pattern of efficient costs over the forthcoming revenue control period for specific categories of works or expenditure

- **Business case (or cost-benefit) analysis** - under this approach, the cost submissions of the gas transmission businesses must necessarily be underpinned by economic justification, that is, the businesses are required to demonstrate that the forecast expenditure is expected to be the lowest cost option in the long run relative to other feasible options in net present value terms

- **Examination of governance practices** - some regulators also seek information on the internal processes employed by the utilities to assess needs and to underpin the business case for the specified expenditure

- **Statistical (cost) benchmarking** - encompasses many different methods for establishing the efficient costs of the regulated businesses and encouraging them to achieve the long-run efficiency outcomes normally associated with workably competitive markets.

TOTEX approaches

Under a building block approach, operating and capital expenditures are separately treated for the purposes of regulators assessing their reasonableness or efficiency and for then setting allowed revenues accordingly. However, some regulators have moved away from this approach (or adopted a different approach from the outset) entailing the determination of revenue allowances by **combining operating and capital expenditures or, put differently, by assessing total expenditure ('TOTEX')**. Three key considerations motivating the use of a TOTEX approach include:

- **Removal of the 'capex bias'** – it is generally felt that building block approaches favour capital expenditure solutions (eg asset replacement) over opex (ongoing maintenance), as the former would provide a steady stream of profits over the assumed life of the assets.

- **Potential gaming by the regulated firm** - the conventional building block approach may provide a perverse incentive to reclassify opex as capex.

- **Business flexibility for efficient delivery of services** – under a totex approach the regulator adopts a neutral view about whether operating or capital expenditures should be incurred, which should then encourage the regulated businesses to choose the mix of expenditure that is most consistent with long-term efficiency.

Regulatory frameworks employing totex approaches **rely heavily on statistical benchmarking techniques** for establishing the cost of service. There is generally no reference to separate operating and capital expenditure allowances, nor any reference to the historical costs of the regulated business. In some cases, it is also unnecessary to roll any investments into a regulatory asset base (RAB).

EU regulatory practice

Assessment of operating expenditure

The NRA responses regarding assessments of operating expenditure are summarised in Figure 38 and Figure 39 below. We note that where two approaches or methodologies are used, the map here (and in subsequent figures) shows these countries with a striped pattern (with the stripes in the colour of one of the two mechanisms employed), while countries using three or more methods are shown as a separate category.

As demonstrated in the figures below:

- **Bottom-up assessments dominate as an analytical approach to assessing opex** – this is used by 17 NRAs, with more than half of these (nine) relying exclusively on such assessments and the remainder using them in combination with other methods, usually top-down assessments and/or cost benchmarking.

- **Top-down assessments are also prevalent** – 11 NRAs employ such methods in total, with five apparently relying on this method alone, while the rest use this in conjunction with other approaches.

- **TOTEX is used by the same countries that characterised their overall approach as such**, that is, Germany, the Netherlands and Great Britain. France, however, also employs a TOTEX approach, but only for a subset of TSO expenditure related to IT, buildings and vehicles.

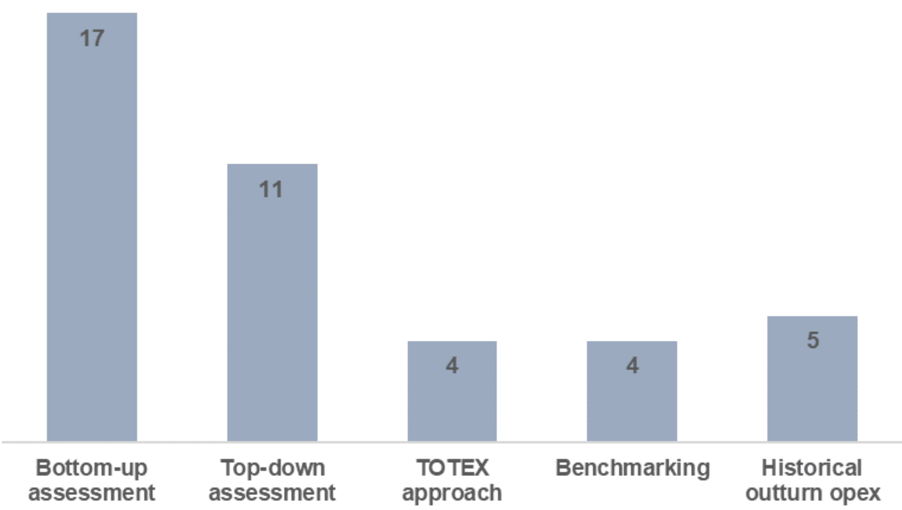
- **Cost benchmarking is generally uncommon, being used by just four NRAs** – as anticipated, statistical benchmarking is employed by the three countries adopting TOTEX approaches, but it is also used as a sense-check for cost assessments using some of the above-mentioned methods by Hungary (but only in limited circumstances ie in relation to employee and rental costs).

- **Five NRAs** (the Czech Republic, Croatia, Spain, Hungary and Italy) indicated that they **use an alternative approach** which was not pre-defined in the questionnaire, but which has similarities across these countries; we have labelled this **"historical outturn opex"** in the figures. Broadly, this approach entails setting future operating expenditures at levels that are commensurate with past or realised expenditures, provided that these are considered to be efficient and, in most cases, after making adjustments for extraordinary costs that were incurred in the reference or base year(s) used for this purpose, allowing for inflation and adjusting for growth in the network.

Figure 7 Cost assessment methods for operating expenditures (by country)

Source: NRAs, ECA analysis

Figure 8 Cost assessment methods for operating expenditures (by type and number)



Source: NRAs, ECA analysis

Assessment of capital expenditure

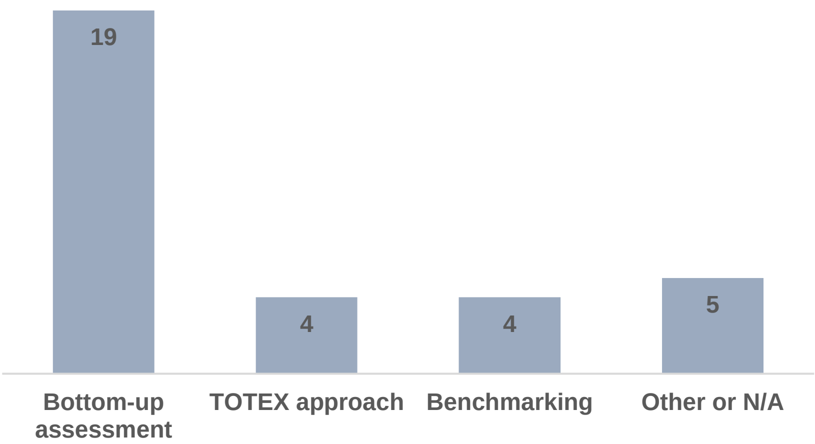
Figure 40 and Figure 41 summarise the corresponding information for the assessment of capital expenditure. Key takeaways from these figures are:

- As with opex, **bottom-up assessments are the main tool employed by NRAs for assessing the reasonableness of TSOs' capital expenditure proposals – such assessments are employed in 19 cases**, mostly as the single analytical approach.
- **TOTEX (as before) is used in Germany, the Netherlands and Great Britain**, with France also employing a TOTEX approach for a subset of expenditure (IT, buildings and vehicles).
- **Cost benchmarking is employed by the three TOTEX countries**, and also Spain which partly uses benchmarked costs for setting allowances.
- **Five countries characterised their approaches as 'other' or 'non-applicable'**.

Figure 9 Cost assessment methods for capital expenditures (by country)

Source: NRAs, ECA analysis

Figure 10 Cost assessment methods for capital expenditures (by type and number)



Source: NRAs, ECA analysis

Efficiency factors

The NRAs were requested to indicate whether cost forecasts or allowed expenditures include efficiency or productivity improvements, whether embedded within the cost forecasts/allowances themselves (eg where these are based on cost benchmarks) or are set over and above the 'base' cost allowances after assessing the reasonableness of TSO cost submissions (as opposed to applying an efficiency or productivity factor at the level of the overall price or revenue control). **In the case of capital expenditures, the use of efficiency factors is not common; it is generally limited to those NRAs applying a TOTEX approach** and therefore efficiencies are embodied in the analysis itself. Beyond these, efficiency considerations for capital expenditure are reflected in Spain, where allowances are partly based on 'reference unit costs' determined under a recent benchmarking/costing study.

In the case of opex, the majority of NRAs (19 out of 27) do apply efficiency factors. The countries that employ efficiency factors for operating expenditure versus those that do not are shown below in Table 17.

Table 2 Employment of efficiency factors when setting opex allowances

NRAs that employ efficiency factors		NRAs that do not employ efficiency factors
1. Austria	11. Lithuania	1. Belgium
2. Bulgaria	12. Luxembourg	2. Denmark
3. Czech Republic	13. Portugal	3. Estonia
4. Germany	14. Netherlands	4. Greece
5. Finland	15. Romania	5. Spain
6. France	16. Sweden	6. Latvia
7. Croatia	17. Slovenia	7. Poland
8. Hungary	18. Great Britain	8. Sweden
9. Ireland	19. Northern Ireland	9. Slovakia (not applicable)
10. Italy		

The regulatory asset base

Theory and issues

Setting an opening asset value

The value of existing assets is fundamental to the determination of allowed revenues because both depreciation and return on capital are calculated from it. There is a wide range of asset valuation methodologies, but there is no single approach that is appropriate in all circumstances. Our broad categorisation and description of these methodologies is as follows:

- **Historical cost accounting methods** – based on the cost of acquiring and renewing assets in the past less the cumulative depreciation on those assets.
- **Replacement cost methods** – based on the cost that would be involved in replacing the service capability of the existing assets, taking account of the cost of replacing their service capability were it to be replaced now and adjusting for depreciation to reflect the remaining useful lives of the assets.
- **Current (economic) value method** – based on the 'value in use', which reflects the present value of future net cash flows that can be expected from the operation of and services provided by those assets. The conceptual problem with a value in use methodology for revenue setting is that the assessment becomes circular – the value in use is itself driven by the anticipated level of revenue.

Because investments in the existing asset base are effectively sunk costs, there is no clear economic rationale for using historical cost accounting methods rather than replacement cost methods or vice versa. In many cases, therefore, regulators use a value that rolls forward directly from the value used in previous decisions, or a value that reflects any explicit, implied or perceived regulatory commitment in previous decisions, or a value that, moving forward, keeps the balance of interests between network users and service providers broadly stable but that remedies any widely perceived current inequity in the balance of interests between them (note than in an established regime, these criteria will coincide).

From an economic perspective, the critical point is not necessarily how the opening asset base is set (although obviously this will be important for network users), but that it continues to be clearly recorded and that it be updated in a consistent manner going forward.

Periodic RAB valuation

Over time, the historical purchase or construction price of assets will deviate from their replacement cost[3]. In most cases, but not always, replacement costs will exceed the historical

[3] This discussion considers whether revaluation to match the replacement cost of assets is desirable for regulatory purposes. It is separate from the mechanics of calculating allowed returns where regulatory agencies may choose to set WACC in real terms (ie, excluding inflation) and to then compensate for the impacts of inflation by uprating the RAB by an inflation index.

cost. It may also be that the actual configuration of assets is no longer (or never was) optimal to meet demand, meaning that customers are paying for assets that are not required to provide the given service. This opens the question of whether to:

- Require that the RAB used in setting tariffs be revalued at regular intervals to reflect their current or replacement costs (including, potentially, optimisation of the asset base against requirements), according to rules established by the regulator

- For regulatory purposes, not allow any revaluation of assets to be passed into tariffs

- Allow the utilities to revalue assets in their financial statements according to their own methodologies and to then use these new values as the RAB going forward.

An implication of the first and second options is that these will lead to the RAB used for regulatory purposes diverging from the asset values in the audited financial statements of the utility. However, this should not be a problem as it is generally now accepted by regulatory authorities that statutory accounting frameworks and conventional accounting values will diverge from the value of the RAB and the criteria for effective economic regulation underpinning that value.

The arguments made for regulatory revaluations of assets generally revolve around the resulting improvements in economic efficiency and, in particular, of delivering tariffs that better reflect the 'true' costs of service. The arguments against such revaluations are they can deliver **'windfall' gains or losses to the owners of the utility** and, depending on the revaluation methodology adopted, they can **create significant uncertainty and risk for utilities over the future value of the RAB** and, therefore, whether they will be able to fully recover their investment costs.

Timing of asset inclusion in the RAB

A key issue that also arises in this regard is when should the capital expenditures be included in the RAB – as incurred, or when a project is commissioned (with the total value grossed up to account for returns on the asset during construction)? Both approaches have largely the same effect on the incentives of the utility because (assuming the total value is grossed up for returns during construction using the allowed WACC) both are equivalent in present value terms.

The key advantage of adding capital expenditure when it is incurred is that it is easier to administer because there are no complexities related to capital expenditure being incurred in one regulatory period but not commissioned until the next. The key disadvantage is that users may pay for capital expenditure that is not yet operational and will not be for some years ahead (thereby distorting allocative efficiency). This effect can be significant for large assets with long construction periods, which characterise many of the investments in gas transmission. On the other hand, including such large investments only once they are commissioned can create financing difficulties for the utility.

Where new investments are added to the RAB once they are commissioned, a decision is also needed on how financing costs during the construction period should be considered. As mentioned above, an approach that employs the allowed rate of return for grossing up the value of the asset retains investment incentives intact. However, some regulators employ the cost of debt for assets during construction (or other indices, such as an inflation index).

Ex post reviews of capital expenditure

In most regulatory regimes, assets enter the RAB based on incurred investment costs. Including assets into the RAB at their actual cost does not, of course, create incentives for utilities to invest efficiently. Regulators, therefore, may subject proposed investments to reviews of their need and costs before approving them for inclusion in the RAB (thereby allowing their costs to be recovered). This may be done on an *ex-ante* basis, with the value of the investment for inclusion in the RAB being set in advance, or *ex-post*, when the investment has been made and the regulator reviews the reasonableness of the costs before adding them to the RAB (for revenue setting purposes).

Depreciation of the RAB

The use of depreciation to determine allowed revenues is intended to spread the costs of investments out across their useful lives. Because it is important that depreciation reflect the costs of investments across their useful lives, economic asset lives are generally used.

There are various options for the depreciation life and profile applied including straight-line depreciation, a declining balance and sculpted profiles. These give different rates of recovery of the costs of the asset and, therefore, of the timing of revenues from it. Alternatively, an annuity can be calculated which gives a constant revenue allowance for each year of the asset's life, the total value of which is equal to the sum of allowed depreciation and returns.

EU regulatory practice

Setting an opening asset value

Figure 43 summarises the methodologies that were employed by the NRAs (or other authorities) for establishing an opening asset value when the current regulatory frameworks were originally established. We note the following:

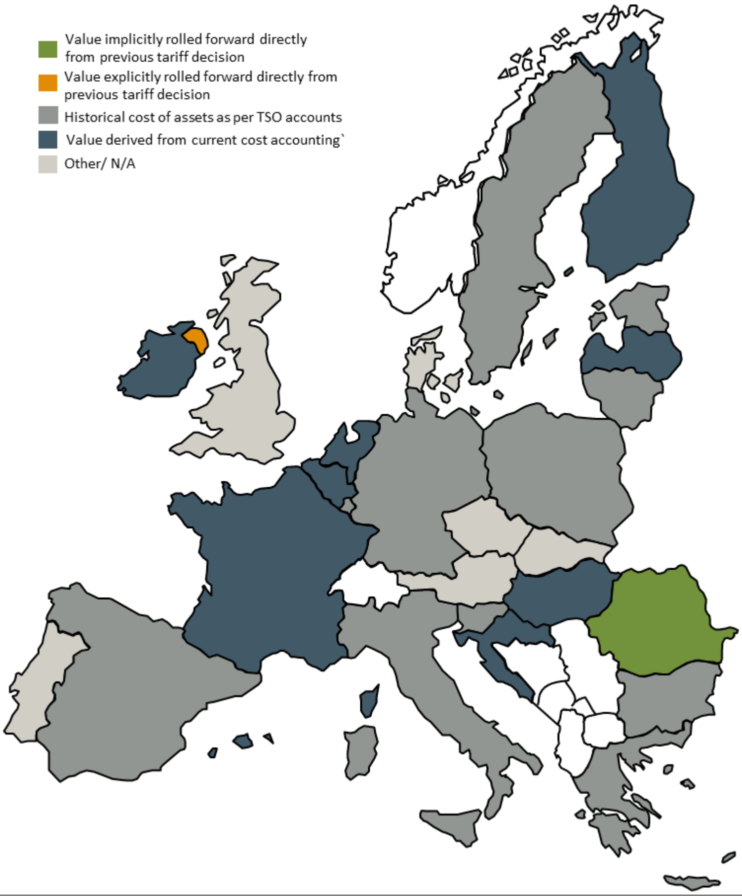
- The most common methodologies employed were historical cost accounting and current (or replacement) cost methodologies:
  - **Historical cost accounting was used in most cases (11 countries) for setting opening asset values**
  - **The next most common methodology was a (current cost) accounting or valuation methodology – this was employed in eight cases**
- **Of the other methodologies pre-specified in the questionnaire**:

- In Romania, the value rolled forward from the value *implicitly* used in previous tariff/revenue decisions (ie the value was 'backed out' from the tariff levels prevailing at the time)

- In Northern Ireland, the value rolled forward from the value *explicitly* used in previous tariff/revenue decisions.

❑ **Several NRAs (five) indicated that 'other' approaches were used.**

Figure 11 Methodologies used for establishing opening asset values (by country)



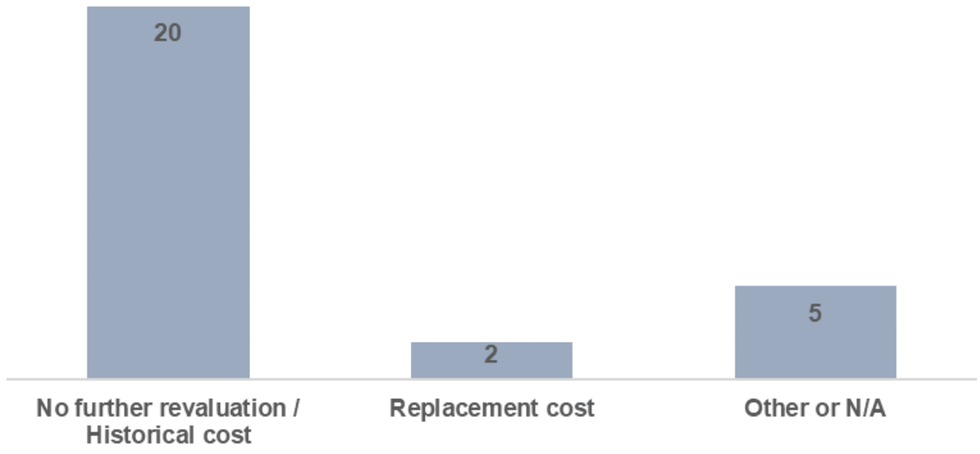
Source: NRAs, ECA analysis

Periodic RAB valuation

Irrespective of how the opening value of the RAB was established, there is a separate question regarding the updating of the RAB over time. In general terms, the valuation options are either to roll in investments (and deduct depreciation) without any further adjustments or revaluation, or to periodically revalue using a current cost methodology.

The vast majority of NRAs (20 out of 27) adopt the former approach, ie there is no further revaluation of the RAB (see Figure 44), irrespective of whether a current cost methodology was used to establish the opening value. We note that some in this group do index the RAB for inflation, but this is because it is needed for reasons of consistency given that they employ a real WACC (that is, indexation is not undertaken as an approximate approach to setting asset values at current costs).

Figure 12 Methodologies for periodically updating the RAB (by type and number)



Source: NRAs, ECA analysis

As shown in the figure, **two NRAs use a replacement cost methodology for the periodic revaluation of the asset base**. Finally, there are **five NRAs** that **use other approaches** or for which the issue of asset valuation is not relevant:

- Austria indexes only the equity portion of the RAB to inflation (because it sets a separate cost of equity in real terms, but a nominal cost of debt)
- Denmark and Slovakia apply unique revenue setting regimes and therefore do not separately account for a RAB
- Finland states that the RAB is calculated every year using "average unit prices and average age-information"
- The German regulatory system distinguishes between old assets (capitalised before 2006, the year that regulation commenced) and new assets (capitalised in and after 2006). These are valued and depreciated differently. New assets (2006 onwards) are depreciated based on historical costs. The share of old assets (pre-2006) financed by debt (minimum 60%) is depreciated based on historical costs. The share of old assets financed by equity (up to a maximum of 40%) is depreciated based on the assets´ replacement values. To calculate these replacement values, historical costs are inflated using price indices.

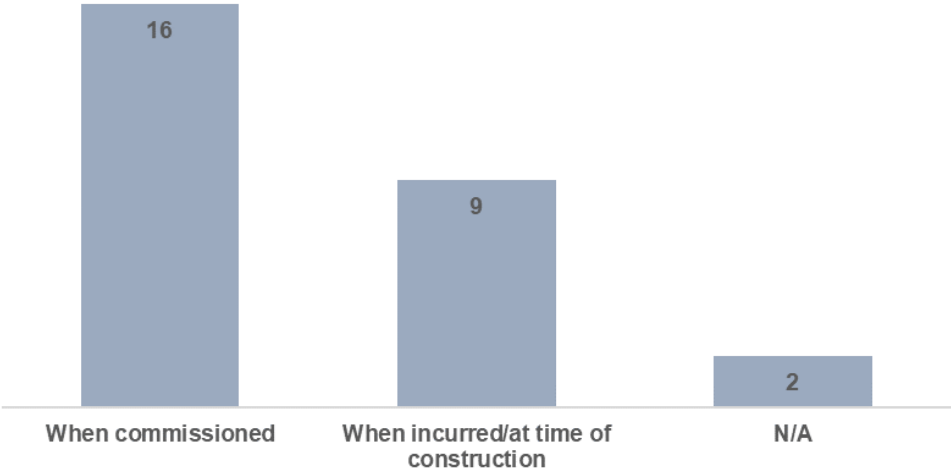
Timing of asset inclusion in the RAB

Figure 45 and Figure 46 below summarise the approach adopted by the NRAs. As depicted in the figures:

- both approaches are used extensively, although **in most cases (16 NRAs) assets are recognised in the RAB upon their commissioning**
- **capital expenditure enters the RAB as spent in nine regimes**

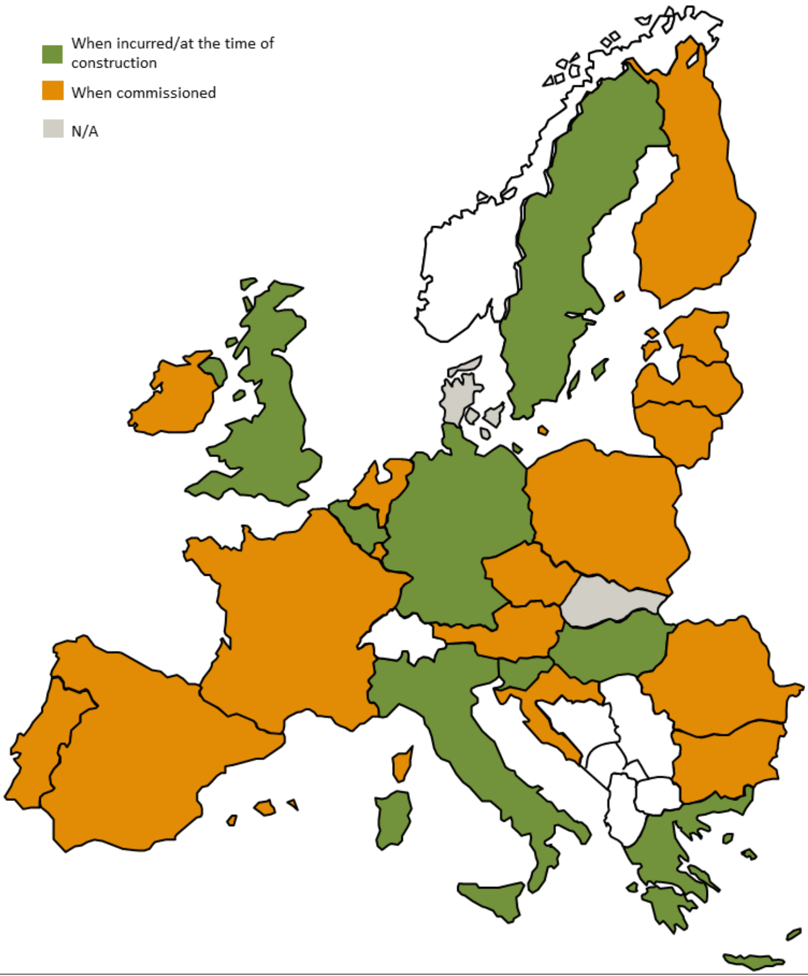
- the issue is **irrelevant for two NRAs** – in Denmark and Slovakia because there is no RAB used for revenue setting.

Figure 13 Timing of rolling investments into the RAB (by approach and number)



Source: NRAs, ECA analysis

Figure 14 Timing of rolling investments into the RAB (by country)

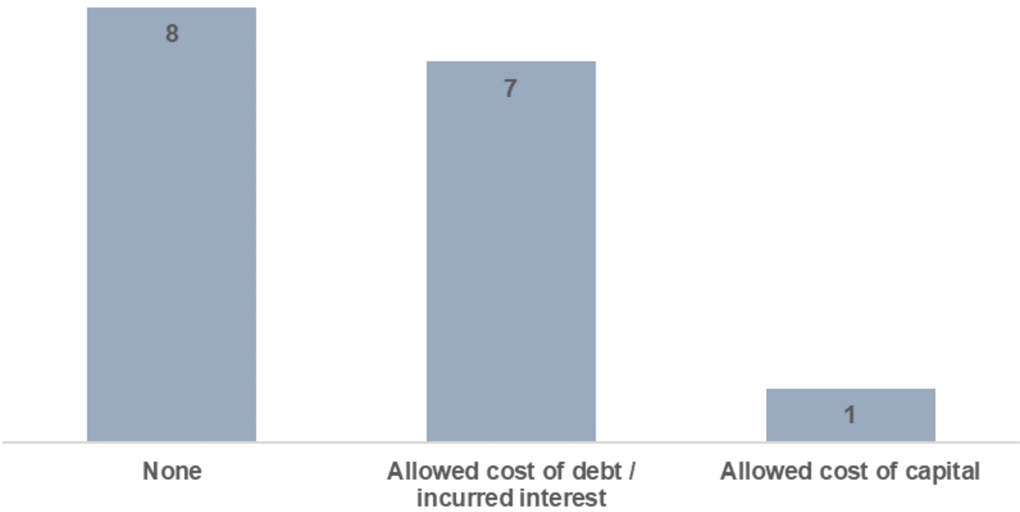


Source: NRAs, ECA analysis

For those 16 NRAs that recognise investments once they are commissioned, an added consideration is whether to recognise any financing costs for the construction period leading up to their commissioning. In response to this question (see Figure 47):

- **eight NRAs stated that financing costs are not recognised** – this applies to Austria, Bulgaria, the Czech Republic, Estonia, Croatia, Lithuania, Luxembourg and Poland
- **another seven NRAs use the allowed cost of debt for rolling up the asset values or recognise the interest costs actually incurred which are usually capitalised into the book value of the assets** – this is the case for Spain, Finland, France, Ireland, Latvia, Portugal and Romania
- **only the Netherlands employs the allowed WACC for rolling up the value of the assets.**

Figure 15 Rate applied for rolling assets into the RAB upon commissioning



Source: NRAs, ECA analysis

Ex post reviews of capital expenditure

Table 18 below shows the countries that undertake *ex post* reviews of capital expenditure versus those that do not, before assets are rolled into the RAB. **The countries are largely evenly split between those that do and do not conduct *ex post* reviews of investments**.

For those that do not undertake reviews, the rationale in many cases is that investments are generally approved through network development plans and hence do not need to be assessed again for need, while other mechanisms (such as required tendering) serve as sufficient disciplines for containing costs.

Among those that do conduct reviews, these are generally undertaken on an *ad hoc* basis and there are no prespecified limits on the scope and materiality of the reviews or defined procedures for how these are undertaken. However, the reviews are mostly focused on 'large' investments (however defined) and where costs deviate substantially from those estimated and/or budgeted at the time of the network development plans.

Table 3 *Ex post* reviews of capital expenditure

NRAs undertaking *ex post* reviews	NRAs that do not undertake *ex post* reviews
1. Bulgaria	1. Austria
2. Denmark	2. Belgium
3. Greece	3. Czech Republic
4. Finland	4. Germany
5. France	5. Estonia
6. Croatia	6. Spain
7. Ireland	7. Hungary
8. Italy[4]	8. Lithuania
9. Luxembourg	9. Latvia
10. Poland	10. The Netherlands
11. Portugal	11. Romania
12. Great Britain	12. Sweden
13. Northern Ireland	13. Slovenia
	14. Slovakia

Source: NRAs, ECA analysis

Depreciation of the RAB

There is broad consensus among the NRAs regarding the depreciation approach, in that **all jurisdictions apply the straight-line methodology** (that is, asset costs are spread evenly over the defined useful life of the assets). The only exception to this general rule are Belgium and Great Britain which use declining balance (or accelerated) depreciation for a "limited number of installations" and for older assets, respectively.

However, while the methodology employed for depreciation is the same, **the defined asset lives vary widely among the EU member states** and NRAs. Table 20 shows the asset lives adopted for some of the main gas TSO asset classes, namely pipelines, compressors, controllers and SCADA/telecoms. **Given that most NRAs also stated that depreciation is not used for the purposes of reprofiling revenues or tariffs, these ostensibly represent different views about the useful life of the assets**. As shown in the table:

- **Pipeline** asset lives range from **30 to 90 years**, with most NRAs clustered around 40-50-year lives
- **Compressor** asset lives range from **12 to 65 years**, with most NRAs employing 20-30-year lives
- The asset lives of **controllers and metering stations** range from **9 to 45 years**, with perhaps 20-30 years representing the most common range (but there is much variation around this)

[4] Not undertaken to date in practice, although the possibility exists.

- Asset lives for **SCADA and telecom equipment** range from **4 to 30** years, with most in the 5-10-year range.

Table 4 Assumed asset lives (years)

Country	Pipelines	Compressors	Controllers, metering stations	SCADA, telecom
Austria	30	12	12	12
Belgium	50	33	33	5 (SCADA) 10 (telecom)
Bulgaria	35	15	15	-
Czech Republic	40	20	10	10
Germany	45 – 65	15 – 30	45	15 – 20
Denmark	35	35	35	-
Estonia	50	n/a	30	-
Greece	40	40	40	5
Spain	40	20	30	10
Finland	50 – 65	65	20	-
France	50	30	30	10
Croatia	35	35	35	-
Hungary	50	20	20	25
Ireland	50	25	15	-
Italy	50	20	20	5
Lithuania	55	20	9	4
Luxembourg	40	40	40	10
Latvia	50 – 60	n/a	20	5 – 30
The Netherlands	55	30	30	5 – 15
Poland[5]	40	25	25	5
Portugal	35	-	-	-
Romania	25 – 40	40	10 – 20	-
Sweden	90	n/a	40	8
Slovenia	35	5 – 15	15	6
Slovakia	n/a	n/a	n/a	n/a
Great Britain	45	45	45	-
Northern Ireland	43	n/a	20	-

Source: NRAs, ECA analysis

[5] We have inferred the asset lives from a generic accounting classification that was submitted in the questionnaire response.

The weighted average cost of capital

Theory and issues

A fundamental element of any revenue determination is the setting of the allowed or target return on capital, which is the return required by debt and equity holders to finance the investment in capital assets. This return applies both to the existing asset base and new capital expenditure or assets, both of which are enshrined in the regulatory asset base or RAB.

The return is generally given by the weighted average cost of capital, or WACC. The discussion that follows is structured around the WACC concept and its various components, although it is recognised that some regulatory regimes separately treat the cost of debt and the return on equity.

The WACC concept

The WACC considers the two components of the cost of capital, the cost of debt and the cost of equity, and is calculated by taking the weighted average of the two, weighted by the relative importance of each type of financing in a company's capital structure. The generic formula for the WACC is as follows:

$$WACC = g \times CoD + (1 - g) \times CoE$$

Where:

g is the gearing level (or the proportion of debt in the capital structure)
CoD is the cost of debt
CoE is the cost of equity.

WACC calculation and tax treatment

There are three different approaches to computing the WACC (depending on where in the revenue calculation tax is factored in, since profit is taxed while interest is tax deductible):

- **Pre-tax WACC** – a pre-tax cost of equity must be determined that incorporates tax on profits. Mathematically, this requires multiplying the after-tax cost of equity by the factor 1/(1 - t), the 'tax wedge'.

- **Vanilla WACC** – this computation does not apply the tax wedge and therefore allows for a post-tax cost of equity (and thus a post-tax WACC) but requires that a separate allowance be made for tax on profits as a separate amount in the composition of the required revenues.

- **Post-tax WACC** – the cost of debt is multiplied by the factor (1 – t) to capture the tax benefit associated with gearing (as interest is deducted before tax is calculated). When using this approach, care is needed in calculating tax allowances, as the tax deductibility of interest costs is already captured in the

WACC formula (ie interest costs should therefore be excluded from the calculation of the tax building block of the revenue equation).

Real or nominal WACC

One fundamental design issue regarding the WACC is whether to set it in real or nominal terms - a nominal return includes inflation whereas a real return excludes inflation. The key is to be consistent, ensuring that the utility is compensated for inflation but is only compensated once. If the asset base is indexed to inflation, then the WACC should be set in real terms (ie it should exclude inflation). If the asset base is calculated using historical/ nominal costs, then the WACC should be in nominal terms (ie it should include inflation).

Cost of equity – the Capital Asset Pricing Model

In estimating the cost of equity, the fundamental question to be addressed is, what rate of return would be necessary to attract equity finance? For this purpose, most regulators (outside North America) adopt the Capital Asset Pricing Model (CAPM) to address this question[6].

The central tenet of CAPM is that the main explanatory factor for the rates of return implicit in market valuations is an asset's (perceived) sensitivity to systematic risk (also known as non-diversifiable risk or market risk). The level of systematic risk is represented by a number referred to as beta (β). The standard CAPM formula for the minimum expected rate of return (after taxes) on an investment ($\mathrm{r_{expected}}$) that would make the investment attractive to investors is:

$$\mathrm{r_{expected}} = \mathrm{RFR} + \mathrm{MRP} \cdot \beta_{\mathrm{investment}}$$

In this formula:

- ❑ The RFR is the risk-free rate, the rate of return that would be available from a risk-free investment
- ❑ The MRP is the market risk premium, the additional return (over the risk-free rate) that can be expected from a balanced portfolio of investments in an investment market (sometimes also referred to as the Equity Risk Premium, or ERP)
- ❑ $\beta_{\mathrm{investment}}$ is the exposure to market risk in the investment, the extent to which the investment's returns and the returns from the wider market are expected to co-vary (ie vary in sympathy).

The theory applies to any investment asset, but is most useful when thinking about the cost of equity (CoE), post-tax, with reference to an equity beta:

$$\mathrm{CoE_{post-tax}} = \mathrm{RFR} + \mathrm{MRP} \cdot \beta_{\mathrm{equity}}$$

[6] Other approaches include the Dividend Growth Model (DGM), which is commonly used in the US and as a cross-check in other jurisdictions, Multi-Factor Models and Surveys of investors and analysts.

Each of these variables needs to be estimated – there are various approaches to estimation, and it is fair to say they are all contentious (see the main report for a discussion of the issues).

Cost of debt

The cost of debt is the interest payable to lenders. In a regulatory context, the first basic decision to be made is:

- whether to pass-through actual interest costs, or
- to separately calculate an interest cost and set an *ex ante* WACC with the regulated company then keeping or incurring the difference between the allowance and its actual interest costs (as an incentive for it to borrow/re-finance efficiently).

In other words, where an *ex ante* interest cost is determined, this is then combined with the allowed cost of equity to obtain an estimated WACC which, when multiplied by the RAB, gives the overall allowed return. The utility is then responsible for meeting interest payments out of this return.

If the decision is taken to estimate an *ex ante* cost of debt, then a further basic design decision is needed on whether this should be a current or 'spot' estimate or whether it should reflect the historical (or 'embedded') interest costs of debt, calculated with reference to market indices or other indicators (and whether these are specific to the regulated company or look broader at comparator businesses).

In practice, these approaches need not be mutually exclusive. For example, a company's expected costs of existing debt could be used as the return on embedded debt, whilst the return on expected new debt could be set using a market-based estimate.

Gearing

There are two main options for setting gearing in the WACC:

- **Actual gearing** – the actual capital structure of the company as it currently stands or is expected to stand over the regulatory period is used
- **Notional gearing** – a notional level of gearing is used, based on what may be considered a typical, objective or efficient capital structure without regard to the actual capitalisation of the company under review.

EU regulatory practice

WACC basis

A variety of approaches are used among the EU NRAs, as summarised in the map of Figure 48 below. More specifically, the following approaches have been adopted:

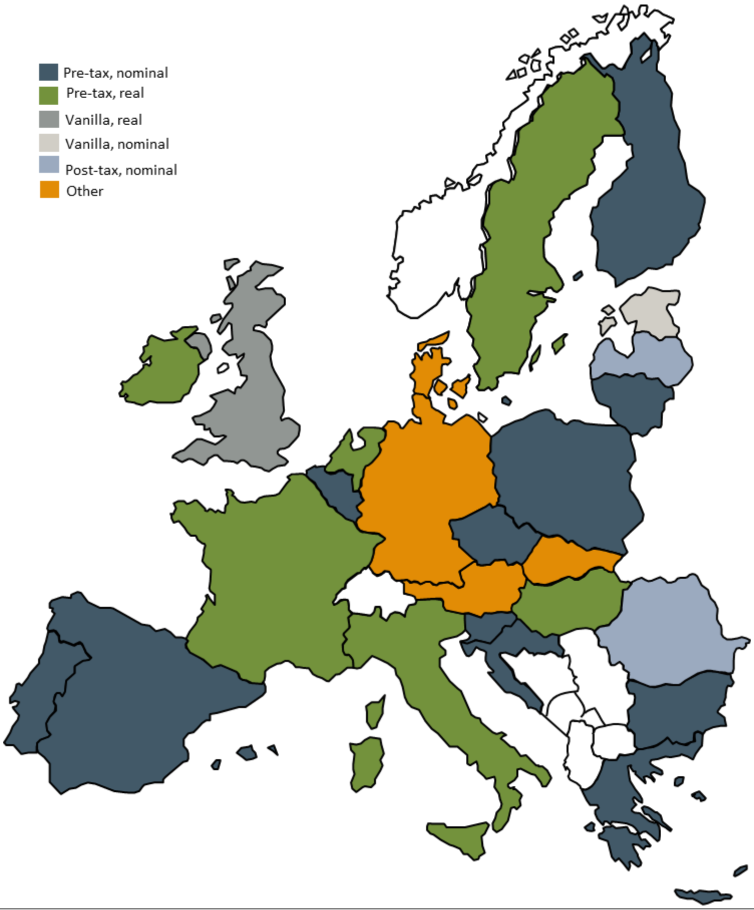
- **Pre-tax nominal WACC is the most common, used by 12 NRAs** – Belgium, Bulgaria, the Czech Republic, Greece, Spain[7], Finland, Croatia, Lithuania, Luxembourg, Poland, Portugal[8] and Slovenia
- **Pre-tax real regimes are the next most prevalent, used in six countries** – France, Hungary, Ireland, Italy, the Netherlands and Sweden
- **A vanilla WACC is used in three jurisdictions** – in Great Britain and Northern Ireland where it is set in real terms, and in Estonia which employs a nominal vanilla WACC
- **Two NRAs employ a post-tax nominal regime** – Latvia and Romania
- **Four countries have other approaches**, as follows:
  - Austria, Germany and Denmark all treat the cost of equity and debt separately
    - Austria sets a pre-tax real cost of equity and a pre-tax nominal cost of debt
    - In Germany, actual debt costs are recognised in allowed revenues subject to assessing their reasonableness against interest costs that are "customary in the financial markets for similar borrowings"; the cost of equity is determined employing a conventional CAPM approach, however given that 'old' (pre-2006) assets are valued at replacement cost, the cost of equity is set in real terms, whereas for 'new' assets (2006 onwards) it is set in nominal terms (both costs are in pre-tax terms)
    - Denmark sets the cost of equity broadly equal to inflation to maintain the monetary value of the assets. Regarding debt costs, the government-owned TSO participates in the Danish Government's relending system with beneficial interest rates on government loans which constitute close to 90% of its reported interest-bearing debt.
  - Slovakia does not explicitly set an allowed rate of return, relying on tariff benchmarks for setting allowed tariffs.

A final observation that can be made is that **nominal regimes are much more prevalent than real** (15 versus eight) and **most regulators prefer to work in pre-tax terms** (18 versus five) thereby abstracting from formal tax calculations.

[7] We note that Spain does not have a WACC strictly speaking. Instead, the NRA uses an interest rate of 5.09%, which is calculated based on the price of money in Spain for 10 years plus 0.5%.

[8] In Portugal, due to the uncertain and financially unstable environment since 2011, the rate of return is updated *ex-post* (each 'gas year') in order to reflect the evolution of financial market conditions. The WACC for the TSO, applied since July 2013, is indexed to the Portuguese 10-year bond benchmark and depends, in each year, on its evolution, with a cap and a floor.

Figure 16 WACC basis (by country)



Source: NRAs, ECA analysis

WACC values

Table 21 below presents the WACCs reported by the NRAs as having been adopted in their most recent regulatory decision. The arrows in Table 21 show the direction of change in the set WACC compared to the previous period (ie whether it increased or decreased or remained broadly equal). As can be seen from the tables, **there is considerable variability in the allowed or target cost of capital across the Member States**.

Table 5 WACC values by country and basis (most recent regulatory period)

Country	Pre-tax nominal	Pre-tax real	Vanilla real	Vanilla nominal	Post-tax nominal
Austria					
Belgium	3.74%v				
Bulgaria	8.14%^				
Czech Republic	7.94%^				
Germany					
Denmark					
Estonia				5.63%n/a	
Greece	9.22%v				

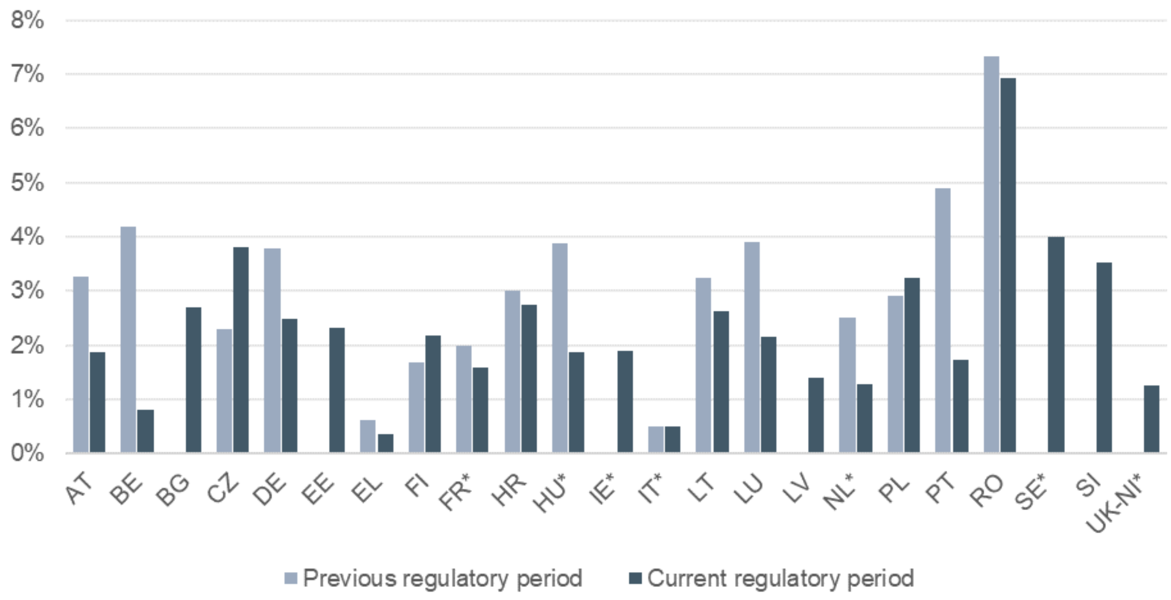
Country	Pre-tax nominal	Pre-tax real	Vanilla real	Vanilla nominal	Post-tax nominal
Spain	5.09%+'RCS'[9] v				
Finland	7.38% =				
France		5.25% v			
Croatia	5.22% v				
Hungary		4.62% v			
Ireland		4.63% v			
Italy		5.40% =			
Lithuania	5.80% v				
Luxembourg	6.12% v				
Latvia					4.68% v
Netherlands[10]		3.00%/3.6%/4.3%[11]			
Poland	6.19% ^				
Portugal[12]	6.04% v				
Romania					9.41% v
Sweden		6.91% n/a			
Slovenia	6.98% n/a				
Slovakia					
Great Britain			4.38% v		
Northern Ireland			2.11% ^		

The risk-free rate

Figure 51 below shows the risk-free rates used by the NRAs for setting the WACC in the two most recent regulatory decisions (wherever relevant). We note that caution needs to be exercised in comparing the rates below as they are not on an equal basis – some are nominal and some are real (the latter countries are shown with an asterisk in the graph), while some also include a country risk premium (CRP) while others either do not have such a premium or add this separately or to the MRP. Even with these caveats, it is clear that **there is large variability between the RFRs used, and these to a large degree explain the variance in the adopted WACC values** (given that there is less variability in the MRP and to a lesser degree in the equity betas).

[9] According to the Spanish NRA (CNMC), a WACC is not explicitly set, rather financial compensation is provided based on the price of money in Spain for 10 years plus 0.5% and the RCS is an amount of money that is included in allowed revenues serving to 'improve' the WACC (like a WACC premium).
[10] The WACC varies by year and type of investment. The CoE is uniform throughout, but the RFR and CoD vary depending on the year and whether capex is for replacement/refurbishment or expansion (as it takes into account embedded debt costs, if relevant). Eg, the WACC for replacement/ refurbishment investments (real, pre-tax) is set at 4.3% in 2016 and 3.0% in 2021. For expansion investments, it is set at 3.6% in 2016 and 3.0% in 2021.
[11] The NRA's decision is the subject of an appeal, so these values might change.
[12] This is the average for the regulatory period.

Figure 17 Risk-free rates by country (last two regulatory decisions)



Note: Countries with an asterisk have real rates; all others are nominal. Some countries (eg Greece and Hungary) add a country-risk premium (CRP) on top of the RFR, while others (eg Romania) incorporate it in the RFR. In the case of Portugal, a combination of the two approaches was used across the two most recent regulatory periods – in the previous period the CRP was added to the RFR, but in the current period it has been added to the MRP.
Source: NRAs, ECA analysis

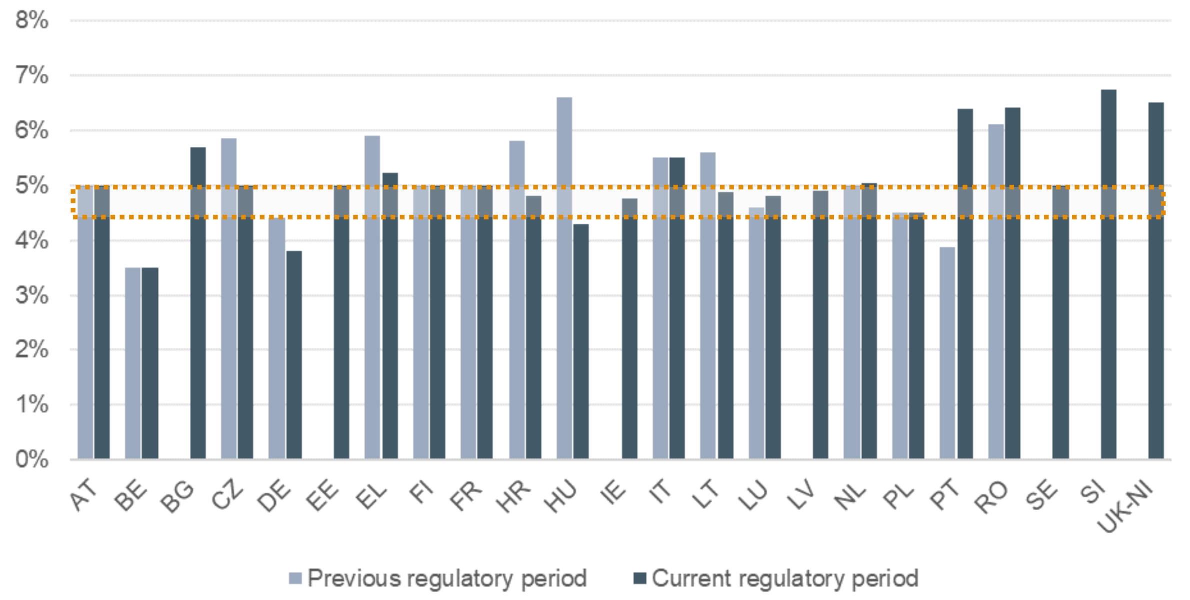
The market risk premium

The market risk premiums (MRPs) adopted by the NRAs show **more consistency between regulatory periods and across countries** – see Figure 52 below. Looking at the most recent regulatory periods, the majority of the countries (almost half) used an MRP in the 4.5%-5.0% range. More specifically (and excluding Denmark, Spain, Slovakia and UK-GB where the issue of an MRP is irrelevant or was not stated):

- There are **13 countries currently employing an MRP between 4.5% and 5.05%** - Austria, the Czech Republic, Estonia, Finland, France, Croatia, Ireland, Lithuania, Luxembourg, Latvia, the Netherlands, Poland and Sweden
- **Three countries have set an MRP below 4.5%** - Belgium (3.5%), Germany (3.8%) and Hungary (4.3%)
- **Three countries have an MRP between 5% and 6%** - Bulgaria (5.69%), Greece (5.23%) and Italy (5.5%)
- **Four countries have employed an MRP greater than 6%** - Portugal (6.38%, which is inclusive of a country risk premium), Romania (6.42%), Slovenia (6.75%) and UK-NI (6.5%).

We attribute the broader consistency in the MRPs to the fact that most NRAs use very long-term data (in many cases dating from the early 1900s) to estimate the premium, which tends to remove the effects of shorter term fluctuations in equity markets.

Figure 18 Market-risk premiums by country (last two regulatory decisions)



Note: The MRPs for Portugal are not comparable as the rate for the previous period excludes the CRP, whereas it has been included in the MRP for the current period. Also, the MRPs shown are the averages used within the pre-specified floors and caps.
Source: NRAs, ECA analysis

The equity beta

In the figure below, we show the equity betas that were adopted by the NRAs in the two most recent regulatory periods (wherever available). We note again that the higher the beta, the higher will be the cost of equity and/or WACC applied (given that the beta is multiplied by the MRP and added to the RFR to derive the cost of equity).

As shown in Figure 53, **the vast majority of NRAs apply an equity beta below 'one'** (the solid line in the graph below), indicating that NRAs consider regulated TSOs to be less risky than the market as a whole. The only exceptions (ie those Member States with an equity beta higher than 'one') are Bulgaria (1.08) and Slovenia (1.07), which seems incongruous given that the former states that it relies on precedents adopted elsewhere, while the latter calculates beta based on a broad group of EU companies (and therefore mostly uses a similar sample to many other NRAs). Moreover, both NRAs apply revenue caps, which arguably removes a large element of systematic risk (ie volume/demand volatility).

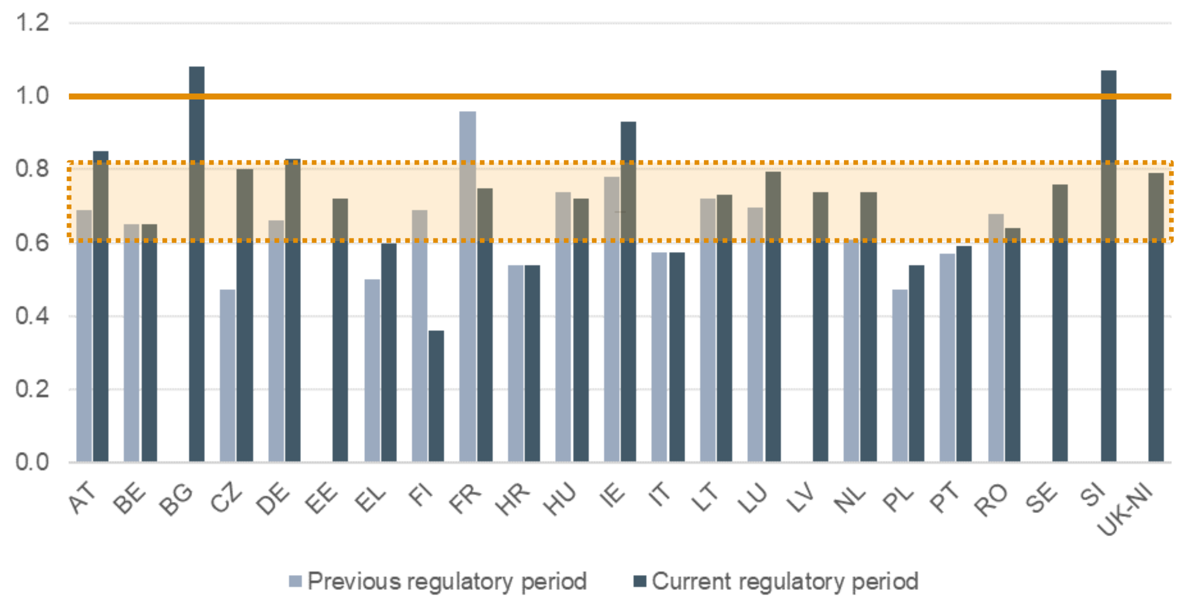
Of the remaining countries where an equity beta is set or has been stated (so this again excludes Denmark, Spain, Slovakia and UK-GB), we note the following:

- **Most (13) NRAs have adopted an equity beta between 0.6 and 0.8** (as highlighted by the coloured box in the figure) - this is true of Belgium, the Czech Republic, Estonia, Greece, France, Hungary, Lithuania, Luxembourg, Latvia, the Netherlands, Romania, Sweden and UK-NI

- **Three NRAs employ a beta between 0.8 and 1.0**, namely, Austria (0.85), Germany (0.83) and Ireland (0.93), although all three had lower betas and in the 0.6-0.8 range in the previous regulatory period

- **Five NRAs use an equity beta below 0.6** – Finland (0.36), Croatia (0.54), Italy (0.575), Poland (0.5389) and Portugal (0.59).

Figure 19 Equity beta by country (last two regulatory decisions)



Source: NRAs, ECA analysis

The cost of debt

Turning to the cost of debt component of financing costs, most NRAs set the cost of debt on an *ex ante* basis (ie without subsequent correction for realised debt costs). In particular:

- **23 NRAs set debt costs this way (ie *ex ante*)** – Austria, Bulgaria, the Czech Republic, Germany, Estonia, Greece, Finland, France, Croatia, Hungary, Ireland, Italy, Lithuania, Luxembourg, Latvia, the Netherlands, Poland, Portugal, Romania, Sweden, Slovenia, Slovakia and UK-NI

- **Two NRAs set the cost of debt *ex post*** – Belgium and Denmark

- **Two NRAs employ some other mechanism** – Spain, where there is no WACC applied but a financing rate (covering the cost of debt and equity), and UK-GB, which sets debt costs based on a trailing index of corporate bonds (the 'iBoxx non-financials index' for A and BBB credit ratings), although this is also applied on an *ex ante* basis.

Of the 24 NRAs setting the cost of debt *ex ante* (including UK-GB):

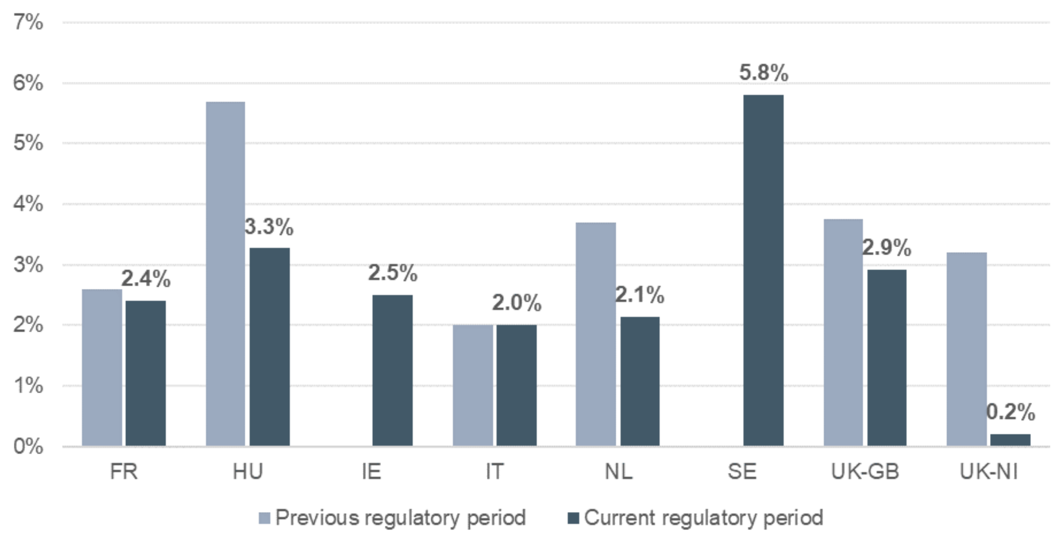
- **16 NRAs use an RFR plus debt premium approach** – Austria, the Czech Republic, Estonia, Finland, France, Hungary, Ireland, Italy, Luxembourg, the Netherlands, Poland, Portugal, Romania, Sweden, Slovenia and Slovakia

- **Eight NRAs set debt costs based on observed yields** (although different proxies are applied for the market cost of debt) – Bulgaria, Germany, Greece, Croatia, Lithuania, Latvia, UK-GB and UK-NI

The following two figures show the resulting cost of debt adopted for both real and nominal regimes, respectively. Some observations based on these are the following:

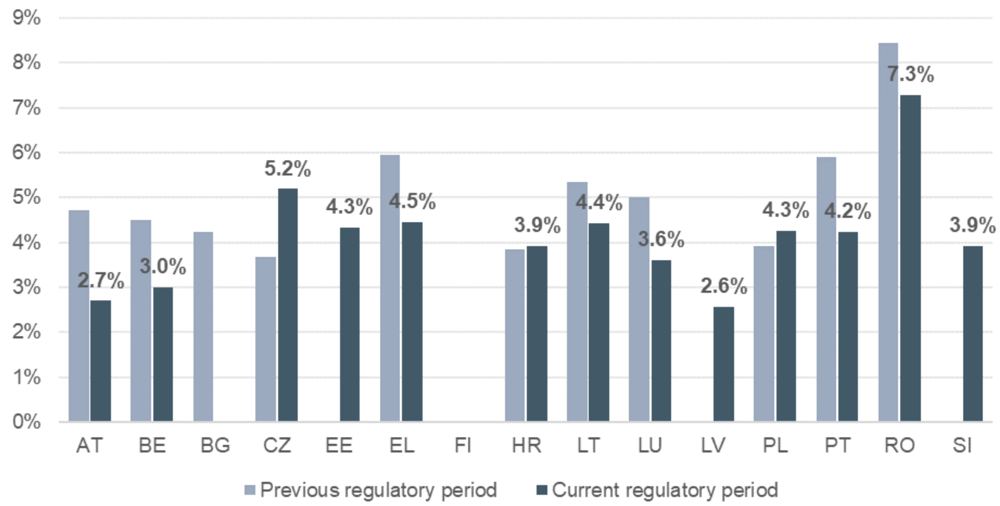
- ❑ **Allowed debt costs have mostly (although not universally) fallen between the previous and current regulatory periods**
- ❑ In those countries applying **real rates**, there is broad comparability of debt costs, with **most falling in the 2%-3% range**, with the outliers being, at the upper end, Sweden (5.8%) and, at the lower end, UK-NI (0.2%)
- ❑ In those countries with **nominal regimes, debt costs are generally in the 3%-4.5% range**, except for Austria and Latvia which are a little below the lower end of the range and the Czech Republic which is a little above the upper end, while Romania appears to be the outlier with an allowed cost of debt of 7.3%.

Figure 20 Cost of debt (real) by country (last two regulatory decisions)



Source: NRAs, ECA analysis

Figure 21 Cost of debt (nominal) by country (last two regulatory decisions)



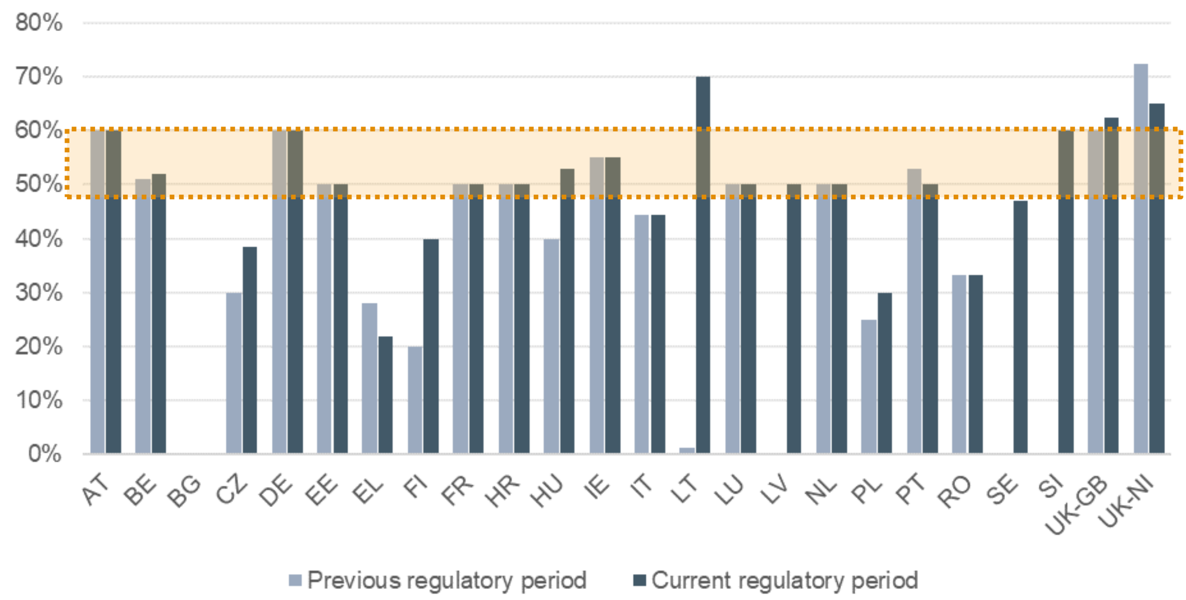
Source: NRAs, ECA analysis

Gearing

Of those NRAs that use the WACC concept (and therefore need to apply weights to the equity and debt components), **22 use notional gearing and only two NRAs use actual gearing** (Bulgaria and Greece). The gearing levels employed are shown in Figure 57 below. As demonstrated in the graph:

- **Most NRAs, 13 in total, apply a gearing level of 50%-60%**
- **Three NRAs respectively use gearing levels in each of the following ranges**:
  - **61%-70%**, namely, Lithuania, UK-GB and UK-NI
  - **40%-50%**, these being Finland, Italy and Sweden
  - **less than 40%** - Bulgaria, the Czech Republic and Greece.

Figure 22 Gearing level by country (last two regulatory decisions)



Source: NRAs, ECA analysis

Other regulatory mechanisms

Theory and issues

Over or under-recoveries of revenue

As the nature of a revenue cap regime is that utilities are protected for changes in volume or capacity, it is necessary for the regulatory framework to allow for adjustments for differences in realised energy consumption or capacity utilisation (and the mix across different customer classes) between forecast and actual. In making corrections for the above factors, there are essentially two options:

- ❑ Annual adjustments (whether lagged or not)
- ❑ A single adjustment, which is made at the end of the regulatory period and rolls up the annual differences (using the allowed cost of capital or other parameter as a proxy for the time value of money).

Subject to the utility continuing to be able to finance its activities, it should be largely indifferent between the two timing options, where the adjustments are present value neutral (if a time value of money below the firm's cost of capital is used, then this condition will not hold).

Treatment of underspends and overspends

The revenue setting methodologies discussed earlier, and especially the Building Blocks methodology, are employed to set a baseline revenue requirement on an *ex ante* basis for a given regulatory period. However, there may be a need to adjust revenues to account for outturn costs and activities (ie on an *ex post* basis).

One key issue in this context is whether to apply **efficiency sharing (or rolling) mechanisms** ie adjustments to revenues deriving from savings in operating and capital expenditures (compared to projections used for setting the revenue requirement), but applied in a way that incentivises utilities to pursue such efficiencies while simultaneously ensuring that the benefits are shared with users.

Such sharing (and related incentive) mechanisms for operating and capital expenditures have slightly different implications due to the way they are incorporated into allowed revenues (directly for opex, indirectly for capital expenditure through depreciation and return on capital over time). The use of sharing mechanisms for capital expenditures is primarily about ensuring constant incentives throughout the regulatory period. Even in the absence of a sharing mechanism, capital expenditure under/over-spends are shared between utilities and users through lower/higher future depreciation (if actual rather than forecast depreciation is used in the asset base roll-forward equation) and return on capital.

Opex is different. If utilities under-spend on opex, they keep the full benefit in that year and users do not share any direct benefit (only indirect benefits in the form of lower opex allowances in the next regulatory period). It is for this reason that some regulators apply an opex sharing mechanism, ie to guarantee that opex savings are directly shared between utilities and consumers.

Performance metrics and rewards/penalties

Some regulatory regimes have incentives for utilities to maintain or improve service quality levels as well as to reduce costs. This is done to ensure (especially with price/revenue cap regimes) that improvements in cost efficiency are not at the expense of quality of service.

The regulation of quality in the gas transmission sector is multi-faceted and many operational aspects will already be regulated through minimum standards and regulations (eg for safety). However, beyond such standards, some regulatory frameworks contain a performance regime for utilities, which is generally limited to a small number of factors that concentrate attention on those aspects that are likely to be important to users (and for which there is reliable and useful data).

Once key performance indicators are established, rewards and penalties are developed for their achievement or failure. These rewards and penalties are then applied as adjustments to the allowed revenues.

EU regulatory practice

Over or under-recoveries of revenue

The questionnaire issued to the NRAs requested that they indicate whether revenues and tariffs are adjusted for over and under-recoveries within the regulatory period (eg annually) or between regulatory periods (cumulatively). The responses indicated that:

- **Eight NRAs adjust revenues between regulatory periods**
- **Seven NRAs adjust revenues within regulatory periods**
- **Seven NRAs stated that they do both** – we interpret this as meaning that revenues are adjusted annually, but shortfalls or over-recoveries in the final year of the regulatory period naturally carry over to the next period.

The NRAs employ many different approaches regarding the mechanics of the adjustments, regarding, for example:

- the time over which they are spread (eg this was sometimes dependent on the level of adjustment, with higher adjustments being spread over more years)
- whether penalties are applied (as an incentive to ensure accurate forecasting and individual tariff setting by the TSOs)
- whether adjustments are made for all revenue variations or only if they are material (and exceed certain bands)
- whether the treatment is symmetrical (between shortfalls and over-recoveries).

The NRAs also display much variability in the rate used for the time value of money when making the adjustments. By way of example (and without necessarily covering all NRAs):

- Several use a short-term borrowing rate, whether this is by reference to a particular published rate or an administratively specified (and relatively low) interest rate
- The most popular approach (although still among a minority of NRAs) was to apply a price index, in most cases CPI
- The weighted average cost of capital was used only by two NRAs, and in one case a percentage point penalty on the WACC is applied if over-recoveries are 'large'

- A couple of NRAs use the allowed cost of debt, while two others employ the risk-free rate (although for one NRA, this forms the base to which an unspecified premium is added).

Treatment of underspends and overspends

As discussed above, incentive-based regimes sometimes foresee, after having set the baseline revenue requirement, adjustments to revenues to account for outturn costs and activities. This is typically done to retain constant incentives for TSOs to pursue efficiencies and to share the benefits of cost savings (or the burden of cost overruns) with network users. Having explored this issue with the NRAs, we found that there is fairly limited use of such adjustment mechanisms, currently. More specifically:

- **For opex**:
  - **Six NRAs use efficiency sharing mechanisms** (where, typically, a sharing rate in per cent is applied to the over/under spend accumulated during a regulatory period)
  - **One NRA uses a rolling mechanism** (where a TSO retains/incurs the benefits/costs of an underspend/overspend for some specified time)
  - **One NRA uses a different mechanism** – this is Hungary, which employs a profit-sharing mechanism irrespective of the cause of over-recovery (so also applies to capital expenditure). The approach used can be characterised as 'asymmetrical earnings sharing', that is, if the TSO earns profits above those allowed, then 50% of the difference 'may' be shared with network users, but there is no adjustment for lower profits than those allowed. Although the mechanism does not necessarily apply automatically, the NRA has always made adjustments in practice.
- **For capital expenditure**, there is even more restricted use:
  - **Three NRAs use sharing mechanisms** – Spain, where assets are rolled into the RAB based on the average of actual cost and 'reference unit costs' used for setting allowed revenues, Luxembourg, where a 30/70 (TSO/network users) symmetrical sharing mechanism applies, and UK-GB where a sharing ratio of 44.36% (applied to TOTEX) was used in the last regulatory decision.

Performance metrics and rewards/penalties

There is limited use of performance regimes or other similar incentive mechanisms, with only the following **four NRAs specifying that such incentives are used**:

- **Austria** - TSOs are measured on the following performance metrics (with weighting in brackets): customer satisfaction (25%), unplanned availability time (25%), transparency obligations and quality of data (25%), environmental aspects (15%), and agency cooperation (10%). This is a reward-only incentive regime, with up to 5% of opex (excluding the cost of fuel gas) 'at risk'.

- **Finland** – rewards are paid when energy not supplied (ENS) is in the top quartile when compared to the reference years (2008-2015). Penalties apply when ENS is in the bottom quartile, and there is a deadband in the middle. The scheme applies symmetrically: +/-2% of 'reasonable return' for the year.

- **France** – there is a quality of supply regime entailing 16 different metrics and other schemes, including additional rewards for implementing large investment projects (>€20m) significantly below budgeted costs (and corresponding penalties for significant cost overruns), and an R&D funding scheme.

- **UK-GB** – there are various schemes in place that cover financial, statutory and reputational incentives.

Evaluation of EU methodological practices

Assessment framework

Here, we provide a broad evaluation of the key elements of the revenue setting methodologies adopted by the EU NRAs and which were summarised and discussed above. For this purpose, we apply the assessment framework summarised in Figure 58 and entailing the following:

- focusing on **five key aspects of the regulatory approaches** – the overall framework (or, more precisely, the form of revenue control), the setting of expenditures, the asset base, the cost of capital, and other (adjustment and incentive) mechanisms

- application of **three broad assessment criteria**, covering economic ***efficiency*** (productive, allocative and dynamic), ***risk allocation*** (for volume and costs) and other general ***regulatory and/or consumer objectives*** (such as transparency, simplicity, predictability and regulatory gaming)

- the drawing of some **observations and conclusions** regarding the possible further development of the regulatory frameworks.

Figure 23 Methodology assessment framework

Source: ECA

Regarding the choice of assessment criteria, we note the following:

- **Economic efficiency** – it is probably uncontroversial to state that the overarching objective of the regulatory framework is to promote the goal of economic efficiency. We employ this term to encompass all dimensions of efficiency typically considered by economists – productive, allocative and dynamic and therefore it covers the efficient **operation** of and **investment** in the gas transmission system, both **now** and into the **future**. The promotion of economic efficiency is also closely linked with many of the objectives of EU legislation (including of the Gas Network Tariff Code), for example:

- ***Market integration*** – this is important, among other things, to the extent that it minimises the cost of investing in, operating and using the gas network (productive and allocative efficiency)
- ***Security of supply*** – this requires the matching of supply and demand and therefore needs to be underpinned by efficient investment (productive and dynamic efficiency)
- ***Interconnected networks*** – similar to market integration, this is significant because it may minimise overall investment and operating costs (productive efficiency).

- **Risk allocation** – revenues and tariffs are invariably set in advance, so realised outcomes will inevitably deviate from forecasts. A key element of the regulatory framework therefore is how the risk of realised outcomes differing from those forecast are allocated and managed (between the regulated company and network users and perhaps third parties). While there are different classes of risk that could be examined, our focus here is on:
  - ***Volume risk*** ie that outturn volumes or capacity will differ from forecasted volumes/capacity, and
  - ***Cost risk*** ie where actual costs are different to those that were forecasted or allowed.
- **Other regulatory and consumer issues** – under this heading we group several other criteria that are important from a practical implementation perspective, such as transparency, simplicity, predictability and reduction of regulatory costs (including those associated with regulatory 'gaming').

The evaluation is structured around the five respective regulatory elements forming the focus of the assessment. Depending on the framework element, we also **focus only on specific aspects of the three broad assessment criteria, as some are more relevant than others and do not always carry the same weight**. We also emphasise that the assessment draws out relative strengths and weaknesses and should not be interpreted as a scoring mechanism with unambiguously better approaches.

Overall regulatory framework

The most common method currently employed by EU NRAs is a revenue cap. This is followed by hybrid regimes that employ cost-plus for capital expenditure and a revenue or price cap (or combination of the two) for operating expenditure. Pure price cap and cost-plus regimes are much less prevalent, while a few NRAs apply other frameworks that cannot be readily captured under the abovementioned models.

The assessment below focuses on price and revenue caps, and cost-plus regulation, as hybrids will display elements of these regimes depending on the actual design and mix of approaches employed.

The choice between revenue control mechanisms is not unambiguous, and is likely to depend on the circumstances of the country/sector and also the weighting placed on different objectives by the NRAs and other stakeholders. A summary of our assessment of the main regimes is provided in Table 23 below.

Table 6 Summary assessment of revenue control mechanisms

Criteria	Revenue cap	Price cap	Hybrid	Cost-plus/RoR
Productive efficiency	✓✓ Reducing costs maximises profits	✓✓ Reducing costs maximises profits	✓ Reducing costs may maximise profits, but incentive is muted depending on hybrid design (eg might apply just to opex)	✗ No strong incentives for cost minimisation
Dynamic efficiency	✓ May be consistent with profit maximisation, but also incentive to delay investments	✓ Mixed incentives – innovations that reduce future throughput discouraged, but incentive to meet and expand demand	✓ Mixed incentives – depending on the hybrid design, will display features of the other models	✓ Mixed incentives – no strong incentive for cost minimisation, but consistent with expanded service coverage
Allocative efficiency	✓ Generally associated with more passive pricing strategies but also consistent with demand management	✓ Theoretically provides greater incentives for efficient pricing, but not consistent with demand management	✗ Incentives depend on the hybrid design, but unlikely to be as high as under pure revenue or price caps	✗ No strong incentives for efficient pricing or demand management
Volume risk allocation	✓✓ Risk placed on network users (which is consistent with the prevalence of fixed costs in gas transmission)	✗ Risk placed on the regulated firm, although little ability for TSO to manage volume risk in the short term	Uncertain	✓ Risk shared between regulated firm and network users – if volumes affect costs, then risk passes to users (and vice versa)
Cost risk allocation	✓✓ Cost deviations generally borne by the regulated business	✓✓ Cost deviations generally borne by the regulated business	✓ Mixed impacts, depending on design (eg opex cost differences borne by firm, but investment costs differences borne by network users)	✗ Cost differences are fully passed through to network users
Tariff stability	✓ Tariffs vary with volumes (to maintain revenues) so are volatile, but can be smoothed over time	✓ Tariffs stable within a regulatory period, but there could be step changes between regulatory periods when volumes are re-forecast	✗ Mixed impacts, but volatility likely to be higher than revenue and price caps (especially where capital expenditures are cost-plus)	✗ Tariffs likely to be volatile given that they closely track cost variability

Criteria	Revenue cap	Price cap	Hybrid	Cost-plus/RoR
Regulatory gaming	✓ Incentive to forecast high costs	✕ Incentive to forecast high costs and low demand	Uncertain – depends on design	✓ Susceptible to gold plating investments (to increase returns)

Source: ECA
✕ Little consistency with the criterion
✓ Some consistency with the criterion
✓✓ Potentially strong compatibility with the criterion

Incentive-based regimes (revenue and price caps) theoretically provide much stronger incentives than cost-plus/RoR regimes on minimising costs and place the risk of any cost deviations on the TSO rather than network users, which is consistent with efficient risk allocation (if costs are controllable).

The impacts on dynamic and allocative efficiency are ambiguous, with the different control mechanisms providing mixed incentives (of a different type each), although issues of allocative efficiency are directly regulated now through the tariff structure provisions of the EU Gas Network Tariff Code.

Revenue caps score well in relation to volume risk, but this is also then associated with higher tariff instability (although in practice this can be managed through revenue smoothing mechanisms). Finally, **incentive-based regimes (particularly price caps) are subject to regulatory gaming, but cost-plus/RoR regimes are also not immune to this**, given the bias to increasing the capital base (and therefore returns).

On balance, **most EU NRAs seemingly place more weight on efficiency incentives and removing volume risk from the TSOs**, which should therefore (other things equal) lower the cost of capital, and they therefore favour revenue caps. However, **a significant number continue to use cost-plus arrangements for capital expenditures**. We suspect that this might largely derive from gaming concerns and a desire that TSOs do not have an incentive to artificially inflate (and therefore profit from) cost forecasts. This (ie obtaining accurate costs forecasts) is one of the largest challenges of regulation and is discussed immediately below.

Determining and setting expenditures

Setting the revenues at a level that is commensurate with 'efficient costs' (given reliability and security of supply standards) is at the centre of NRAs' tasks and of the challenges they face. The difficulty arises because of the **information asymmetries between the TSO businesses and the regulators** – the latter have imperfect information about the TSOs' actual costs, demand and service quality (the TSO has more information about these attributes than the regulator or other interested parties), but **regulators are required to make judgements about these matters so that they can set revenues broadly equal to efficient costs and/or to define the magnitude of (and the time for closing) any efficiency gaps**.

We explore two main questions given the state of development of cost assessment by EU NRAs:

1. Do NRAs need to devote more effort (and resources) to TSO cost assessment? – the answer to this question is closely tied to the purpose of cost assessment and therefore

the efficiency criterion - and, if so, is there merit in moving to more 'sophisticated' forms of assessment such as cost benchmarking and/or TOTEX approaches? – this depends on the assumed degree of inefficiency in the gas TSO sector (versus the added cost and complexity of more 'advanced' or detailed cost assessment).

2. If more detailed cost assessment is justified, how could these other approaches be adopted and applied?

Is greater scrutiny of TSO costs warranted?

Economic efficiency is at the heart of any cost assessment method as the aspiration is that TSO costs are minimised (productive efficiency), tariffs are then set in accordance with efficient costs (allocative efficiency) and efficiencies are also maximised over time (dynamic efficiency). However, increased efforts to determine efficiency generally come at the expense of increased regulatory complexity and cost. This may be seen by the summary review below of the cost assessment methods identified earlier and setting them against (a subset of) the evaluation criteria.

Table 7 Summary evaluation of cost assessment methods

Criteria	Bottom-up	Top-down	Benchmarking	TOTEX
Efficiency	✕ Limited efficiency incentives, given focus on individual costs	✓ Holistic approach should deliver stronger efficiency incentives	✓ Strong efficiency incentives given revenue-cost decoupling	✓✓ In principle, most consistent with efficiency as it also removes incentive to favour one type of expenditure to increase profits
Regulatory cost/complexity	✓✓ Least costly approach as only firm-specific costs are assessed (albeit generally requires detailed examination of individual cost items/categories)	✓ Requires access to a dataset of (partial) efficiency or productivity measures of comparator companies	✕ Extensive and complex data and modelling requirements	✕ Extensive and complex data and modelling requirements plus major change to regulatory regime and approach

Source: ECA
✕ Little consistency with the criterion
✓ Some consistency with the criterion
✓✓ Potentially strong compatibility with the criterion

As shown in the table, while the more sophisticated cost assessment methods are relatively more consistent with efficiency principles theoretically, there are correspondingly much more intensive and complex data and analytical requirements associated with these.

A key question then (given the current heavy reliance on bottom-up assessments) is whether the increased regulatory burden of employing benchmarking or other related tools can be justified. The answer depends on the current level of inefficiency in the EU TSO sector. Some inefficiency is likely to exist (it does even in highly competitive markets), but **the critical point is whether the inefficiency is sufficiently large to necessitate closer scrutiny of TSO costs and the use of more rigorous cost assessment methods**. The question is somewhat circular, as benchmarking and statistical analysis would be needed in the first instance to provide empirical evidence for the presence or absence of large inefficiencies. However, *a priori*, there are grounds for believing that inefficiencies are likely to be material:

- by virtue of their monopoly status, TSOs are shielded from competition (and the absence of competition is generally associated with reduced efficiency)
- TSOs cannot be allowed to become insolvent – regulators generally have a legal obligation to ensure the financial viability of the TSOs and in any case TSO bankruptcy would not be tolerated (politically and socially) given the large disruption costs and security of supply concerns
- whatever evidence does exist (notwithstanding data and sampling size deficiencies) from cost benchmarking studies of network industries, suggests that there are very large divergences between the most and least efficient businesses.

In principle therefore, it would seem that **more detailed scrutiny of TSO costs might be warranted**.

How should more 'advanced' assessment methods be employed?

There are several options to using cost benchmarking, including to:

3. Act as a diagnostic tool to help assess the reasonableness of bottom-up proposals
4. Set expenditure allowances within a building block framework, for example, by combining (partial productivity measures) with some top-down assessment of particular cost categories
5. Set the efficiency factor, based on total factor productivity growth, to set operating cost or revenue growth
6. Provide information to network users and others (through regulatory reporting), thereby providing pressure for improved performance by TSOs
7. Set revenues based purely on the cost benchmarking results (as is common under TOTEX approaches).

While over time cost benchmarking may play a more deterministic role in setting revenue allowances (as with TOTEX approaches under point 5 above), we would expect that for most NRAs the more appropriate use of benchmarking would be for one (or more) of the first three listed purposes ie effectively to **provide a challenge to TSO forecasts and/or provide a path for the achievement of efficiency and productivity gains over time**. However, even at this level, considerable effort would be needed in determining the information to collect, and standardising data collection and benchmarking processes. We would suggest that **these processes are best defined at an EU-wide level**, if possible, and the information thereby generated could also be (subject to any confidentiality provisions) **published in regular benchmarking reports** (as per point 4), which of themselves can provide incentives for improved network performance.

The regulatory asset base

An important regulatory objective is **to underpin confidence that the opening value of, and the basis for rolling forward, the RAB are stable**, thereby providing a firm foundation for future investment decisions. Given this and the fact that all EU regimes are now well established, **there is no rationale in our view in departing from the adopted starting asset values**. **This would create considerable regulatory risk and potentially undermine future investment** or at least result in TSOs requesting a higher cost of capital to compensate them for the added risk and uncertainty created by the precedent of revising established asset values. Because the costs are sunk, there is also no clear economic rationale for any change (to counterbalance the added regulatory risk).

For similar reasons, **we would favour that the entire RAB *not* be periodically revalued using replacement costs**. Nevertheless, we do believe that there ought to be **greater scrutiny of actual expenditure that enters the RAB, which currently occurs in an automatic way in many cases or with limited review**, particularly given the heavy reliance on cost-plus arrangements for the capital expenditure component of revenue allowances and the absence of other incentive mechanisms for addressing overspends.

The weighted average cost of capital

Efficiency considerations would require that the cost of capital is set 'accurately' (ie not too high or too low). However, there are practical difficulties to this, especially for the cost of equity, which can only be partially observed through *realised* returns on comparable assets (but even this cannot be measured reliably and may not in any case reflect *expected* future returns).

The implications of this is that an evaluation of the approaches to setting the cost of capital is difficult and there is **no unambiguous way of choosing between alternative estimation methods**, all of which have their own theoretical strengths and weaknesses. Consequently, **our discussion below attempts instead to draw out some general principles or issues that could be considered by the EU NRAs when calculating the cost of capital, while recognising that the detailed rules and design will remain with individual authorities**. However, the discussion is still guided by the assessment criteria and particularly by issues of efficiency, and flexibility versus certainty (and therefore risk).

High-level principles for setting the cost of capital

Estimating the cost of capital **ultimately requires a regulator to exercise judgement about the analytical techniques and evidence that should be employed** to derive the estimate, as well as taking into account the characteristics of the particular regulatory regime and country circumstances. However, we believe that there might be merit in **developing some overarching principles and guidelines for setting the WACC that could be employed at the EU-level, while allowing sufficient flexibility to individual NRAs**. These principles would involve setting out the approach to calculating the cost of equity and could include consideration of the following key issues or features:

- **Cost of capital objective** – as mentioned above, estimating the cost of capital requires judgement but where this is the case it is best (for reasons of transparency and greater certainty for investors and network users) that it be exercised by reference to specific objectives. Our interpretation of the EU legislative framework and current practice among many NRAs is that **the cost of capital should be set so that it reflects efficient financing costs** (versus, for example, by reference to some conception of a 'fair' return). If this is true, it would be worthwhile making this objective (or whatever other objectives are considered important) explicit.

- **WACC basis** (pre or post tax, real or nominal, vanilla) – although there is no efficiency or economic imperative to adopting a common approach, using a common method does have practical benefits in that the **cost of capital can then be more readily compared** on a consistent basis. At a minimum, a requirement to publish the WACC on a consistent basis (irrespective of the underlying approach used) would facilitate such comparisons.

- **Methodology and estimation methods** – while CAPM can remain the foundation model for estimating the cost of equity, consideration could be given to **allowing regulators the flexibility to examine a range of estimation methods, market data and other evidence**. While this necessarily introduces some discretion to the estimation process, it might be necessary to protect either the TSOs or network users when market conditions change adversely.

- **Deterministic estimation or regulatory flexibility** – in many cases, NRAs are employing mechanistic rules for setting certain cost of capital parameters, even within the CAPM framework (such as the risk-free rate which is commonly calculated by reference to 10-year nominal government bonds of Member States). This approach has the advantage of creating relatively greater certainty about the method of calculating the cost of equity (or at least for some components of it, like the risk-free rate), and can be viewed as more objective (particularly where there are many regulated entities) thereby providing greater protection against appeals to regulatory decisions. Nevertheless, the mechanistic approach might be too limiting.

- **Transparency and accountability** –this part of the regulatory framework would benefit from greater transparency in each jurisdiction, entailing a full and considered explanation for cost of capital decisions. Furthermore, we would suggest that **there might be merit in establishing a forum at EU level** (or building into the work programme of existing fora) for developing the principles enunciated above (and others) that can act as general guidelines for NRAs when setting the cost of capital. This forum could also be used for reporting on and learning from the approaches used in other jurisdictions (and in latest academic thinking), explaining why different approaches are taken by certain NRAs or in specific circumstances, and reviewing the cost of capital principles, guidelines and approaches at appropriate intervals.

Other regulatory mechanisms

NRAs generally make limited use of incentive mechanisms for dealing with efficiency gains and losses and quality aspects of TSO transmission services.

Regarding the former (ie efficiency incentives), the incentive mechanisms that are in place are generally limited to opex with savings and losses kept/incurred for the duration of the regulatory period (which means that incentives are not constant through time), or where they are time-neural they do not address the issue of capex bias (given that opex outperformance is rewarded while actual capital expenditure is generally rolled into the RAB with limited review and/or is not subject to any corresponding sharing mechanism). **There is therefore a case for equalising the incentive rates for opex and capital expenditure**. This can be achieved either by adopting TOTEX approaches or introducing comparable incentive mechanisms for capital expenditure to complement existing opex efficiency schemes.

In relation to quality, there is a risk that in an effort to reduce costs (especially under incentive-based regimes that reward cost savings) TSOs do so at the expense of quality. There is therefore a case for the **more widespread use and development of incentives to maintain or improve service quality levels** (as well as to reduce costs).

Final observations

Summarising our assessment of the EU methodologies and distilling some key lessons, we note the following:

- The most common NRA practice is to employ **revenue caps** for controlling allowed revenues (whether in totality or for the opex component), which we consider to be **most consistent with promoting efficiency and with the fact that volume risk is not easily managed by TSOs**. Concerns about tariff instability under revenue cap regimes can be managed through smoothing mechanisms, while the potential for inefficient pricing is now addressed directly by the tariff structure provisions of the Gas Tariff Network Code. **Consideration could be given to expanding the revenue cap to cover the entire revenue allowance** (and not just opex), although this would need to be accompanied by other mechanisms to ensure efficient costs and incentives are set (see below).

- Cost assessment approaches in many jurisdictions remain embryonic and relatively passive and therefore **greater regulatory effort is required to challenge the cost assumptions of the TSOs** and to provide more ‘stretching’ efficiency targets. This might need to consider the possibility of employing cost benchmarking techniques and measures as a way of challenging TSO forecasts. There may also be a case for establishing an EU-wide procedure for collecting standardised information from TSOs and publishing data on comparative network performance.

- **There are no strong efficiency grounds for revisiting opening (or starting) asset values** and unless it is considered that there are large imbalances (between TSOs and network users) it is best to retain these values to underpin confidence in undertaking future investment. Also, NRAs, with few exceptions, broadly favour rolling forward actual expenditure rather than periodically revaluing and updating the RAB. This appears to us consistent with minimising regulatory risk and complexity, lowering the cost of capital and promoting investment.

- **There needs to be greater scrutiny of new investment and capital expenditure and/or incentives to minimise costs and remove potential biases for**

undertaking capital expenditure. This can be achieved in several ways and needs careful consideration by NRAs of the relative incentive properties of the various mechanisms or package of measures:

- **TOTEX approaches** – the adoption of such a regime requires NRAs to undertake considerable development work and would represent a major change from current regulatory practice, so beyond the current NRAs using TOTEX this is likely to be adopted in just a limited number of countries at the present time.

- ***Ex post* reviews of capital expenditure** – especially in the context of cost-plus arrangements and in the absence of other efficiency incentives, NRAs should employ *ex post* reviews to ensure that only prudent and efficient investment is rolled into RABs. Even in the presence of other regulatory mechanisms, such reviews could be used sparingly where there is potentially credible evidence of overspending.

- **Incentive mechanisms** – the current focus by most NRAs on operational outperformance and the differential treatment of opex and capital expenditures might create a bias for the latter, while many of the opex incentives employed by EU NRAs do not provide consistent incentives throughout the regulatory period. NRAs should therefore consider the design and implementation of mechanisms that ensure efficient spending and its neutral treatment (regarding the choice of both timing and expenditure type).

- **For the cost of capital, we believe it neither necessary nor desirable to establish prescriptive rules and a common EU approach**. But, there would be value in developing **high-level guidance at the EU level** which would then be employed by NRAs for their more detailed rules, and to then have greater sharing of thinking and analysis between NRAs, as well as periodic reviews of the underlying principles to reflect current best or common practice.

- **Quality of the transmission network service needs to be given greater prominence in NRA regulatory frameworks**, especially if moving from cost-plus arrangements to a greater reliance on efficiency incentives and incentive-based regulation. Such metrics might typically cover factors such as system reliability, damage incidents, gas leaks and unaccounted for gas, emergency responses, asset management practices, pipeline corrosion and community liaison.

- **Reporting should be improved** – incentive-based regulation, in particular, requires detailed reporting of costs and other parameters of performance. Currently, there is rarely quantification of what assets are built, maintained or operated to deliver gas transmission services. Consideration should also be given to developing a common framework for collecting TSO data, particularly if NRAs choose to employ more benchmarking methods in their cost assessments.

1 Introduction

This Report has been prepared by Economic Consulting Associates (ECA) for the Agency for the Cooperation of Energy Regulators (ACER) under the assignment: "**Methodologies and parameters used to determine the allowed or target revenue of transmission system operators**".

1.1 Background to the assignment

In broad terms, the objective of this study is to document and contrast the methodologies used by regulatory authorities across the EU in determining and setting the allowed or target revenues of gas transmission companies. And, ultimately, to assess (if feasible) whether specific approaches are suited to particular circumstances and if there is room for greater harmonisation to facilitate internal market development. In this regard, key requirements of the assignment terms of reference (TOR) are the following:

> *"…the Contractor will undertake an assessment of* ***methodologies and parameters*** *used in EU Member States to determine the allowed or target revenue of gas transmission system operators"* (emphasis added)
>
> *"The objective of the Study is to provide a* ***systematic analysis of the current practice*** *for setting the allowed or target revenue of gas Transmission System Operators ('TSOs') across the EU"* (emphasis added).

We have interpreted the above as primarily aiming to establish a full dataset and a clear assessment framework for revenue setting methodologies, which in turn requires:

- The comprehensive documentation of current methodologies and approaches used in the EU – this then raises issues around:
  - The scope of the required information (what to collect?)
  - The method of collection and presentation (how?)
  - Reflection of the foregoing in the design of the questionnaire to be issued to the regulatory authorities to obtain the relevant information and the reporting templates
- A well-defined conceptual framework for comparing and assessing the methodological approaches and regulatory practices.

The need for the study derives from the provisions of the Gas Tariff Network Code

Importantly, the need for the study arises from the prescriptions of the Commission Regulation (EU) 2017/460 establishing a network code on harmonised transmission tariff structures for gas ('Gas Tariff Network Code'), which stipulates that:

"Before 6 April 2019, the Agency shall publish a report on the ***methodologies and parameters*** *used to determine the allowed or target revenue of transmission system operators. The report shall be based on at least the parameters referred to in Article 30(1)(b)(iii)."* (Article 34, emphasis added).

The Article 30(1)(b)(iii) parameters are the following:

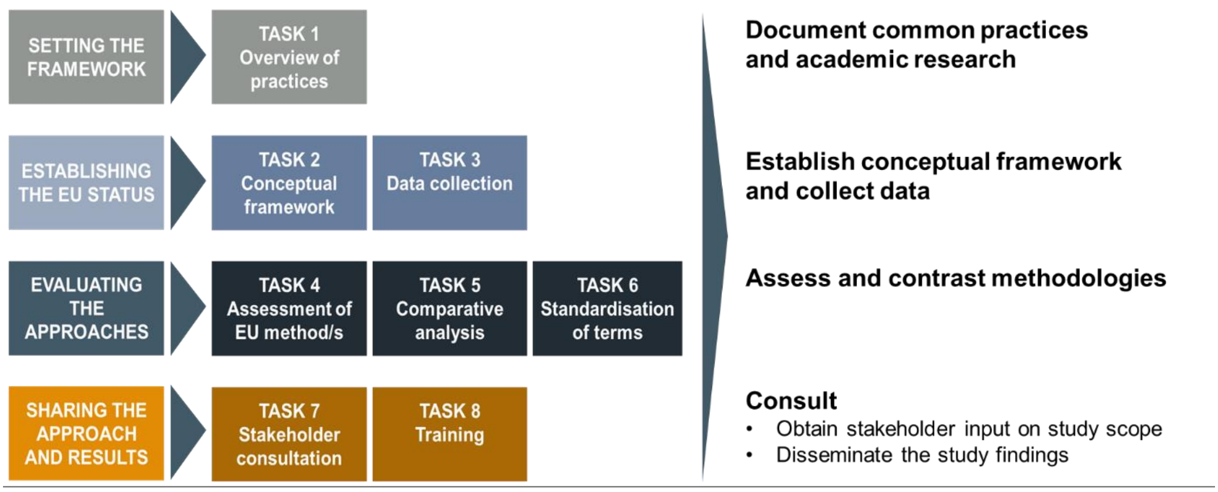
(1) types of assets included in the regulated asset base and their aggregated value
(2) cost of capital and its calculation methodology
(3) capital expenditures, including:
(a) methodologies to determine the initial value of the assets
(b) methodologies to re-evaluate the assets
(c) explanations of the evolution of the value of the assets
(d) depreciation periods and amounts per asset type
(4) operational expenditures
(5) incentive mechanisms and efficiency targets
(6) inflation indices.

The present study is intended to generate the foundation material needed by ACER to meet the above publishing obligations. Given that numerical information is also covered by the annual publications of the National Regulatory Authorities (NRAs) and TSOs, this Report has focused mostly on methodological matters (except where numerical information is important for demonstrating different approaches, particularly those that are largely within the purview of the NRAs, such as the cost of capital and its underlying parameters).

1.2 Scope of work

Figure 24 below captures our approach to addressing the project scope and the logical sequencing of the TOR-specified project tasks.

Figure 24 Project scope and tasks



Source: ECA

As demonstrated in the figure, we have grouped the tasks around four broad activity categories:

- **Setting the framework** – this covers task 1 on the overview of best practices as established from the literature survey, which also serves as the framework for defining and informing the issues, approaches and assessment that follow in subsequent assignment tasks.

- **Establishing the EU status** – this comprises tasks 2 and 3 and represents the information and data gathering stage to establish current practices in the EU. To ensure that the requisite data is collected in a structured manner and in a form that will assist further analysis and evaluation, the conceptual framework (under task 2) must largely be established first.

- **Evaluating the approaches** – having collected all the requisite information, this group of activities entails the assessment and contrasting of the various methodologies and approaches, with the aim of identifying 'best' practices, and includes the documentation and possible standardisation of the terminology used to aid consistent communication in future.

- **Sharing the approach and results** – this refers to the stakeholder consultation session for ascertaining the aspects that should be explored from their perspective (which was held in Brussels on 8 February 2018), and the training to share and disseminate the results of the study.

1.3 Report structure

This Report contains **three parts** - the contents of the first two respectively covering the theory and issues surrounding the setting of regulated revenues for utility network companies, and the findings regarding current EU regulatory practice, are structured around common headings to facilitate cross-referencing and understanding. The third part contains the questionnaire employed to obtain information on current EU regulatory practice preceded by summaries of the responses received and the situation applying for each NRA. These main parts of the report are also supplemented by a few annexes.

More specifically, the structure of the report is as follows:

- **Part I** contains the literature review, and comprises eight sections:

  - Section 2 introduces this part of the Report

  - Sections 3 to 7 respectively review the key aspects of revenue setting, namely the overall revenue control mechanism, the review and setting of expenditures, the regulatory asset base, the cost of capital and other regulatory incentive or adjustment mechanisms

  - Section 8 describes the conceptual approach employed to assembling, presenting and evaluating the data for the present Report

- **Part II** describes and summarises the EU Member State methodologies currently employed for natural gas transmission, using corresponding sections to those in Part I of the report, and with the final Section 15 providing our evaluation of the methodological approaches based on the conceptual framework of Part I

- **Part III** contains country fact sheets for each relevant NRA and the questionnaire that was designed for collecting information from the NRAs and/or TSOs about the approach used for setting and controlling allowed or target revenues.

The Annexes to the report consist of the following – the first four of these inform the discussion in Part I of the report:

- Three country case studies, covering Australia (**Annex A1**), the United States (**Annex A2**) and New Zealand (**Annex A3**), each representing distinct approaches to regulation, namely, incentive-based, rate-of-return and more light-handed regulation, respectively

- **Annex A4**, which summarises the literature reviewed

- **Annex 5** has the template used for summarising the NRA information in the country fact sheets and maps this onto the relevant parts of the questionnaire.

Part I: Literature review and conceptual framework

2 Introduction to Part I

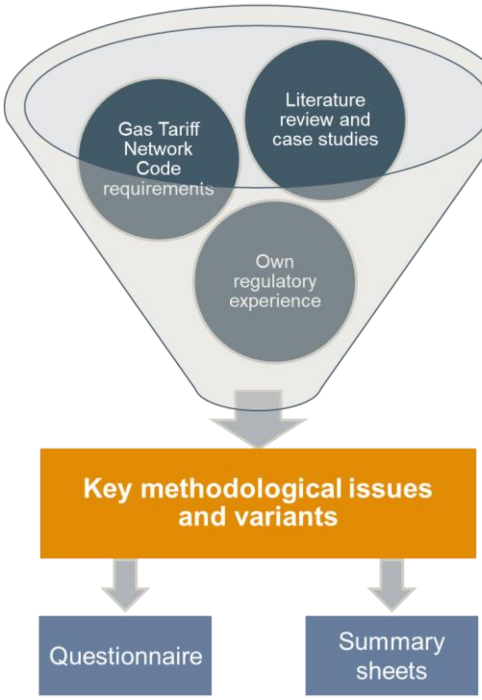
This part of the Report covers Tasks 1 and 2 of the assignment, namely:

- The overview of regulatory practices and issues, and
- The conceptual framework.

2.1 Approach to Part I of the Report

The approach we have undertaken to this part of the Report is summarised in Figure 25 below.

Figure 25 Approach to Part I of this Report



Source: ECA

While the formal requirement of our TOR for Task 1 is to summarise relevant academic and regulatory literature, we have supplemented this with our own knowledge and experience from work in the economic regulation of the energy and infrastructure sectors in developed and developing markets. Moreover, we focus on the parameters stipulated in the Gas Tariff Network Code and **aim at identifying the key methodological issues** arising in this context. This discussion then **informs the design of the questionnaire and the country summary or fact sheets** that seek to capture the essential elements of the various frameworks adopted in the distinct Member States. It also provides the necessary backdrop and the 'interpretative lens' for the description of the regimes in place in the EU that forms the subject of Part II of this Report.

We note that we have refrained from undertaking a mechanistic review of the literature (it is difficult in any case to ensure that we can cover the breadth of the subject matter given the volumes written on regulation). Instead, we have attempted to **set out what we consider are likely to be the key methodological issues (as guided by the Code) that regulatory frameworks either explicitly or implicitly must address and resolve, and which, subject to the choices made, result in differential treatments and outcomes** (potentially). Nevertheless, for a selection of the academic literature we have provided some brief summaries of its scope and subject matter, which could serve as a guide for further reading and research for those interested (see Annex A4).

We also wish to emphasise that there is a limit within the confines of the present study to the methodological issues associated with revenue setting for gas transmission that can be covered. While we have tried to address the matters contemplated by the Code, **there will inevitably be other issues that some stakeholders consider should have been addressed and were not included** (or they might place greater or lesser importance on those we discuss in this Report). Moreover, even for those issues that are contained in this Report, the discussion has generally been kept high-level to ensure that it is tractable (which, given the number of issues, is still quite lengthy).

Finally, we note that there are **different ways that the discussion of the issues can be classified and presented, and how this is done can depend on preferences** and the nature of the regulatory framework that one is usually used to working within. There are also interdependencies between different elements of a regulatory framework and therefore it is not always meaningful to discuss the discrete parts separately (or they might not follow logically). For example, where regulators use 'TOTEX' (total expenditure) approaches to setting allowances, any discussion of separately assessing operating and capital expenditures would be irrelevant. Similarly, where there are revenue cap regimes, the issue of over or under-recovery of revenues naturally follows (given inevitable differences between realised and forecast volumes/capacities), but is irrelevant for price cap regimes.

2.2 Structure of Part I

In any case, for the purposes of this Report and in attempt to capture the various issues and approaches that might be relevant, we have structured the discussion in Part I as follows:

- **Section 3** addresses the overall approach to setting revenues that are generally employed by regulators worldwide
- **Sections 4** through **to 6** cover elements of the framework that are almost universal under any revenue setting framework, namely cost assessment procedures, issues around the treatment of assets and the cost of capital, respectively
- **Section 7** discusses some additional regulatory design issues that might be relevant depending on the context, which mostly have to do with dealing with uncertainties and/or the differences between forecast and realised costs
- **Section 8** contains the conceptual framework used for analysing and comparing the different EU frameworks.

3 Overall framework for setting allowed revenues

In this Section, we provide an overview of the regulatory models used to set the revenues of utilities in comparable sectors (ie gas networks and other energy and infrastructure industries). This overview draws on our experience of working in energy and infrastructure regulation across developed and developing countries, plus the review of relevant literature, which is summarised in Annex A4 and the country case studies of Annexes A1 to A3. The models and methodologies presented in this section are, to some extent, characterisations of the approaches adopted by various regulators, and therefore **provide a useful framework within which to consider the current review of EU practice and develop the questionnaires** addressed to the European National Regulatory Authorities (NRAs).

We consider three main aspects of regulatory models of network utilities:

- The revenue calculation methodologies
- Approaches to adjusting revenues over time
- The length of the regulatory period (where relevant).

3.1 Methodologies for calculating revenue requirements

There are three main alternative methodologies to determining revenue requirements that are used widely around the world:

8. **Cash-based methodology** – this approach focuses on just the cash outlays of the regulated entity (including its debt repayments and interest costs) and tends to be applied in emerging countries that might be developing new markets and that have fast rates of growth in demand, high and (relatively) unpredictable investment needs, high debt servicing costs arising from those investments, and constraints on charging fully cost-reflective tariffs to customers due to affordability concerns. The 'Cash-based' methodology is most notably used in many Latin American countries with those characteristics. It is often used in government-owned systems as a tool for transitioning to cost-reflective tariffs, before moving to the other types of methodologies.

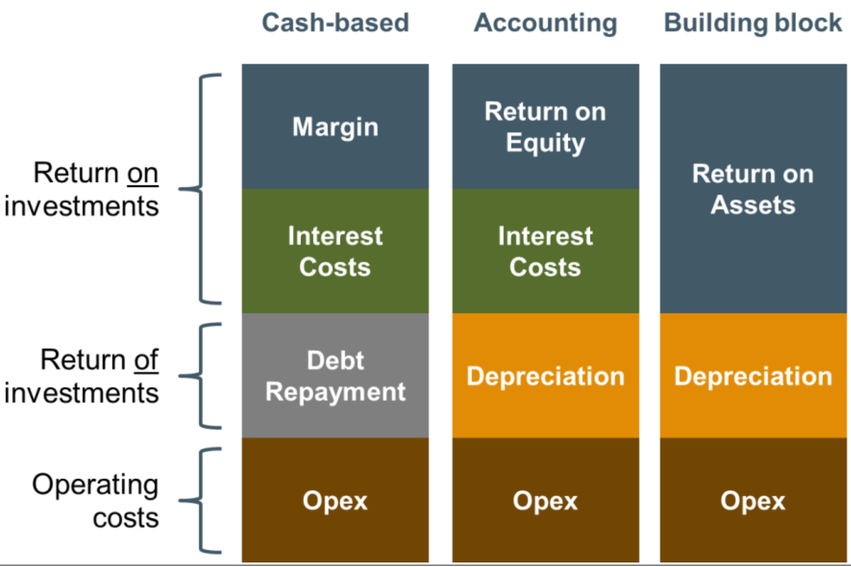
9. **Accounting methodology** – commonly employed by US regulators, this approach heavily relies on setting allowed revenues based on recognised costs under the relevant accounting standards and therefore by mapping revenues to audited financial statements. The set revenues are therefore closely linked to operating expenditure, depreciation and interest costs as appearing in the statutory accounts, although the cost of equity is generally set at a level that is considered 'fair' given the monopoly status of the utility, and capital expenditure is scrutinised for its prudency before being permitted to earn a return and depreciation.

10. **Building block methodology** – applied by numerous regulators in Europe and Australasia, although not always by this name. It is typically paired with a

price/revenue cap ('CPI-X[13]') regime. The revenue requirement is the sum of individual building blocks (that are typically separately assessed and determined *ex ante*), with the costs of making investments recovered through depreciation ('return *of* capital') and return ('return *on* capital') building blocks. A key point is that it tends to suit mature systems with low rates of growth, investment requirements largely driven by replacement of existing assets, and industry structures involving privately-owned enterprises or corporatized (commercial) state-owned enterprises.

The components of revenue requirements under the three methodologies are summarised in Figure 26 below.

Figure 26 Methodologies for setting revenue requirements



Source: ECA (presented at Stakeholder Event in Brussels on 8 February 2018)

The key differences between the three approaches arise from the different treatment of investments, especially how the company (and investors) receive a return ***on*** and a return ***of*** investment.

Key difference 1: Return of investment - depreciation vs debt repayments

The Accounting and Building Blocks methodologies include depreciation in the build-up of the revenue requirement. This allows the utility to recover its costs of investment over the economic or useful life of the asset. If the useful asset life is longer than the repayment term on debt used to finance it, then this can, potentially, cause cashflow issues, especially if the utility has an increasing investment programme. Regulators applying the Accounting and Building Block methodologies therefore sometimes check for cash flow issues, and if one is found, apply some sort of financing adjustment (eg by shortening depreciation lives) to ensure the utility can meet its financing covenants (see also Section 6.6).

The Cash-based methodology simplifies this process by directly including forecast debt repayments in the revenue requirement. This helps ensure that the utility can finance its investments, but the downside is that consumers can end up paying now (ie over the course

[13] Alternatively, RPI-X, depending on the referenced price time series.

of a shorter loan repayment period - eg typically, 10 to 15 years) for assets that are used long into the future (eg 20 to 40+ years).

The other weakness of the Cash-based approach is that it does not fully remunerate equity. This is illustrated by the following example:

- **Accounting and Building Blocks**: The utility makes an investment of €100 that has a life of 10 years. The straight-line financial depreciation under these two methodologies is therefore €10 per year. Over the next 10 years the investor will recover the full €100 invested.

- **Cash-based**: The utility makes an investment of €100 that is 80% debt-funded with a repayment term of 10 years. The debt-repayment component of required revenues is €8 per year (€100*80%/10). Over the next 10 years the investor will only recover €80 and its balance sheet will be €0 (due to financial depreciation). The investor therefore forgoes recovery of the €20 that was financed by retained earnings or an equity injection.[14]

Key difference 2: Return on investment - WACC vs actual interest costs

Under the Building Blocks methodology, the utility's return is calculated as the weighted average cost of capital (WACC) multiplied by the depreciated value of fixed assets (often termed the 'regulatory asset base'). The WACC is determined, in part, by assuming an average cost of debt (ie interest rate) and an average gearing (ie percentage of assets that is funded by debt rather than equity). In contrast, the Cash-based methodology uses the utility's actual costs for year-on-year interest payments and loan principal repayments. The Accounting Methodology generally sets the cost of debt based on the utility's interest costs and determines a fair cost of equity for the equity component of the business, usually employing the actual gearing of the relevant company.

All methodologies treat return on equity (ie shareholder profit) similarly, in that they assume a rate of return and apply it to the equity share of fixed assets. The main difference is in how it is presented – the Building Blocks methodology includes return on equity as part of the WACC/return on capital building block, whereas the Accounting and Cash-based methodologies show return on equity separately.

Comparison of methods

Overall, by explicitly including debt repayment and interest costs in the build-up of revenue, the Cash-based methodology provides greater certainty to lenders that loans will be repaid in full. Consequently, the methodology tends to be better suited to utilities that are in a transitional period of high investment and/or in less mature financial markets, where the utility's cost of debt varies significantly over time.

However, by fully remunerating equity, the Accounting and Building Block methodologies send better price signals to consumers (and investors) than the Cash-based methodology. Therefore, if investment needs are stable (or have stabilised) and the utility has access to

[14] The utility will earn a return on this equity (in the Cash-based methodology, as described) but will not recover its upfront equity injection.

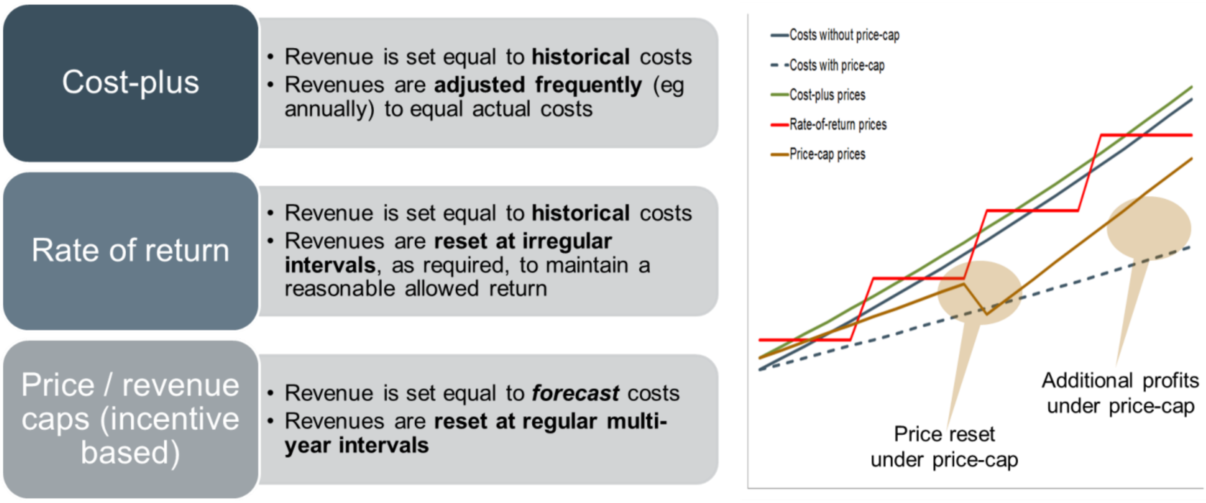
liquid financial markets, then the Accounting and Building Block methodologies tend to be preferred. Moreover, by including an assumed cost of debt (rather than a utility's actual interest cost) in the build-up of revenue (as occurs in some but not all cases of applying the Building Block methodology), the latter might provide incentives regarding the utility's financing (eg if the utility 'beats' the assumed cost of debt, it retains the financial benefits for a period).

3.2 Adjusting revenues

Regardless of the methodology used to establish the revenue requirement, in the absence of revenue adjustments, revenue and costs will inevitably diverge over time. If costs were to rise more than expected, then this could jeopardise the utility's financial position and service to customers. Conversely, if costs were to fall more than expected, then consumers could be paying more than is necessary and the utility earning excess profits. Given those risks and uncertainties, there is a need to adjust revenues to take account of divergences between revenues and costs (having regard also to the incentive impact of any such adjustments).

There are three main regulatory models for adjusting revenue requirements and we summarise these in Figure 27 below and consider them further in the sub-Sections that follow[15]. As noted in the introduction to this Section, these models are characterisations; in practice, regulators use variants of these models (or use aspects of each in combination) with many additional elements and complexities suited to their context.

Figure 27 Main regulatory models for setting and adjusting allowed revenues



Source: ECA (presented at Stakeholder Event in Brussels on 8 February 2018)

3.2.1 Rate of return and cost-plus regulation

Under rate of return regulation, revenues are reviewed following a request either by the regulated company or by the regulator (often prompted by the intervention of an interested party). These circumstances may arise when there is a divergence between revenues and

[15] In reality, there are more approaches (such as sliding scale and menu regulation), but the three described in the main text seem to capture almost all cases employed worldwide for gas networks.

costs such that the company believes its rate of return is too low or the regulator believes it is too high. It is for this reason that the model is referred to as '***rate of return***' regulation. In the review, a utility's revenue can be set based on its *actual* costs, using any of the above methodologies for the components of revenue.

In a more extreme version of this model (usually called 'cost-plus'), reviews are scheduled frequently (eg annually, or more often) to prevent any divergence between revenues and costs, thereby minimising changes in the rate of return.

3.2.2 Price- and revenue-cap (or incentive) regulation

Under this model, revenues are reviewed at predetermined intervals, typically every four to five years. In the review, a utility's revenue is based on a *forecast* of its costs. To the extent that the utility spends less than forecast, it can retain the additional profits until revenues are next reset (in the 'purest' or simplest form of this type of regulation). Conversely, if it spends more than forecast, its will bear the reduced profit (or loss) until the next review. In practice, such regimes have evolved to include other adjustment mechanisms and incentives, but these are discussed separately in Section 7.

3.2.3 Comparison of models

In this sub-Section we highlight some of the key differential features and consequences of the different revenue adjustment models.

Trade-off between efficiency and certain cost recovery

The main trade-off between the three models for adjusting revenues is the balance between the risk to the utility of not recovering its costs and the incentives for productive efficiency.[16]

Incentive regulation provides strong incentives for efficiency, as the utility retains any cost savings it makes during the duration of the price control period, after which the future benefit of these savings is passed on to customers through reduced revenues (see the right-hand panel of Figure 27). The longer the regulatory period, the greater the retained savings and the stronger the incentive for efficiency. In contrast, under rate of return regulation, the divergence between costs and revenues would trigger a review, with the utility only keeping the saving for the time it takes to conduct the review. This 'regulatory lag' means there are some incentives for efficiency under rate of return regulation, but they are muted compared to incentive regulation. In the cost-plus model, where reviews occur annually or more frequently, there is little if any incentive for cost efficiency.

This efficiency incentive, however, involves a trade-off with risk to the utility of not recovering its costs. Under rate of return regulation, if a utility's costs increase, it can seek a review and its revenues will be brought back in line with costs, albeit potentially subject to a slight lag and (potentially) a review to ensure the costs were prudently incurred. In contrast, a utility subject to incentive regulation, must bear cost increases for the duration of the

[16] Productive efficiency is when a product or service is produced at least cost. Allocative efficiency is when products or services sell for their cost (including a normal level of profit).

regulatory period. The risk of a utility not recovering its costs is, therefore, greater under incentive regulation. This trade-off is illustrated in the table below.

Table 8 Illustration of risk/reward trade-off under different adjustment mechanisms

Type of adjustments:	Cost of service	Rate of return	Price/revenue cap
Risk that the business will not recover its costs	Low	Medium	High
Incentives for the business to improve efficiency	Low	Medium	High

Trade-off between cost minimisation and quality

Because of the strong cost incentives under incentive regulation, there is a risk that cost reductions will be made at the expense of quality. For this reason, incentive regulation usually includes minimum quality standards, which are intended to mitigate the risk of under-investment. However, the long-lived nature of typical utility assets means that the effect of under-investment may take time to materialise.

Conversely, the weak incentives for cost efficiency under rate of return regulation means that it can suffer from the opposite problem, with potential incentives for 'gold-plating' investments,[17] although this will likely result in a high quality of service. In practice, the strength of this incentive depends on several factors of the regime, including the cost of capital (with a higher value providing more incentive to over-invest), and whether there are reviews of the prudency of expenditure (and how effective these are).

Simplicity and transparency

It can also be argued that rate of return regulation is simpler and more objective than price/revenue cap regulation. This is a consequence of rate of return regulation relying on actual, rather than forecast, costs. As they are directly observable, actual costs are more objective than forecast costs, and reviewing actual costs is simpler than reviewing cost forecasts. Consequently, the process for setting a price or revenue cap can be long and involved, requiring significant resources both in the company and in the regulator.

Predictability

A final distinction between the models for adjusting revenues is pricing predictability. As price- and revenue-caps are set for a fixed period, they tend to afford greater pricing predictability than rate of return regulation. However, this is not to infer that price-and revenue-caps cannot change during a regulatory period – many regulators will allow for adjustments within the period for factors such as previous under or over-recovery of revenue, or changes in costs over which the utility has no control.

[17] This is referred to as the Averch-Johnson effect, after Averch, H and Johnson, L (1962): "*Behaviour of the Firm under Regulatory Constraint*", American Economic Review, 52, No 5, December 1962, pp 1052-1063.

Rate of return regulation has been the dominant form of regulation in the US – the approach generally used is summarised in Annex A2. However, over the past 25 years, incentive regulation has become more prevalent worldwide – one country with a relatively long history of such regulation is Australia and the current regime employed there is presented in Annex A1, while New Zealand has also recently introduced incentive regulation for gas transmission (see Annex A3). The suitability of one or other regulatory model generally depends on:

- historical reasons and the institutional structure of the relevant country
- legal constraints that might prescribe a certain approach
- perceptions of risk and data reliability
- political acceptance of temporary mismatches between costs and prices
- the relative importance placed on cost-recovery as against efficiency incentives
- specific circumstances of the country and sector (eg mature versus new network, potential for innovation or stable technology, etc).

3.2.4 A practical implication of adjustments under a revenue cap

As the nature of a revenue cap regime is that utilities are protected for changes in volume or capacity, it is necessary for the regulatory framework to allow for adjustments for differences in realised energy consumption or capacity utilisation (and the mix across different customer classes) between forecast and actual. In making corrections for the above factors, there are essentially two options:

- Annual adjustments (whether lagged or not)
- A single adjustment, which is made at the end of the regulatory period and rolls up the annual differences (using the allowed cost of capital or other parameter as a proxy for the time value of money).

Subject to the utility continuing to be able to finance its activities, it should be largely indifferent between the two timing options, where the adjustments are present value neutral (if a time value of money below the firm's cost of capital is used, then this condition will not hold). The main benefit of adjusting revenues or tariffs between regulatory periods would be the minimisation of the administrative burden on both the regulator and the utility. Users may also value stable (and predictable) prices. However, the drawback is that there could be substantial adjustments needed from period to period, resulting in large tariff changes.[18]

Similar considerations arise even under rate of return and cost-plus regulation, where tariffs are set on estimates and then need to be adjusted for realised costs. The only difference is that the adjustment this time is for cost (rather than volume) differences.

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[18] Allowing tariffs to deviate from underlying unit costs is also likely to be inconsistent with allocative efficiency principles, although economic cost reflectiveness is already dampened by the need to recover average costs that are higher than marginal costs and revenue smoothing over the control period (to the extent that this is permitted).

3.3 Duration of the regulatory period

Where price or revenue caps are set for multi-year periods, a key question that arises is how long the regulatory period should be.

A benefit of a relatively long multi-year regulatory period is that it is less burdensome on both the regulator and the utility because a detailed review of costs only occurs every few years. In addition, depending on the incentive mechanisms that might be developed, a longer period may also provide stronger incentives on utilities to outperform *ex ante* assumptions for costs and outputs. Although the latter is the case when other things are equal, it is possible to calibrate the power of incentives independently of the periodicity of the control.

On the other hand, the longer the regulatory period the greater the opportunity for cost differentials (compared to forecast and the allowed revenues) to arise and for the utility to make significant profits or losses.

From our experience, internationally, regulatory authorities appear to have largely settled on a four to five-year regulatory period as representing an appropriate balance between not imposing excessive risk on regulated utilities (or customers) while avoiding too frequent resetting of price controls.

4 Determining and setting expenditure allowances

The building block and incentive regulation process requires the regulated utilities to forecast the operating and capital expenditure necessary to operate their network over the regulatory period. The regulator would then scrutinise the proposals made by the utility and ultimately approve on an *ex ante* basis cost allowances that would be inputs to the allowed revenue calculation and set the maximum revenues for the duration of the control period (subject to any adjustment mechanisms included in the framework).

A principal issue for regulators in making their determination is **how they should assess the expenditure or cost proposals**, for example, whether they should be constrained to undertake a line-by-line assessment of the business's submissions or whether they can apply other analytical techniques and approaches in amending or substituting the utilities' capital expenditure or operating expenditure forecasts. The bulk of this section addresses this issue, that is, we explore the main options available to regulators for establishing allowed revenues (consistent with a building block and incentive regime) and set out some general principles that are applied in undertaking expenditure reviews.

4.1 Determination of efficient expenditure levels

There are a wide variety of alternative approaches that regulators internationally take to establishing allowed costs and revenues. These are not mutually exclusive and there are no hard and fast boundaries between them. Different approaches are often combined by regulators. However, for the purposes of discussing the broad options used, we believe it is helpful to simplify this range of options into the following broad categories:

- Bottom-up assessments
- Yardstick assessments
- Top-down assessments.

We describe each of these approaches below together with a summary of their generic advantages and disadvantages.

4.1.1 Bottom-up assessments

Description

A bottom-up assessment looks at the efficiency and reasonableness of individual cost items proposed by the regulated utility. This usually entails separately determining an allowed cost for individual cost lines which are then summed to obtain the total allowed costs. Further adjustments may then be applied to arrive at the final allowed costs.

The individual cost items might be reviewed in several ways and the approach applied is not necessarily consistent across all cost items. One approach, for example, is largely based on using audited financial statements and historical trends. An alternative is to rely on engineering and process-based analysis. Under these approaches, each individual activity of the utility (rather than accounting line item) is scrutinised and an efficient cost level determined. Proposed investment projects are also reviewed individually to assess the need for them and the reasonableness of the proposed costs. The efficient cost levels may be the outcome of a process of expert judgement and/or be based on a database of the costs of other utilities in performing similar activities. Another possibility is requirements to 'market test' some cost elements by requiring competitive bidding for these.

Assessment

Advantages

The advantages of bottom-up assessments lie in their limited requirements for external data and in the greater likelihood of stakeholder acceptance of the outcomes.

While bottom-up assessments can be very data-intensive regarding the information to be submitted by a regulated utility, **the emphasis on looking at individual cost items means there is much less need than under other approaches to obtain a full set of comparator data**. Instead, assessments can draw on partial datasets, which differ across cost items, and historical cost data for the same utility.

The **greater stakeholder acceptance** derives from a bottom-up assessment placing much more emphasis on looking at the costs of the utility itself, rather than external comparators, and by, in general, the use of much simpler comparisons than the complex statistical analysis required if benchmarking costs against other utilities.

Disadvantages

There are four main disadvantages of bottom-up assessments.

The first relates to the resulting **focus on individual cost items rather than considering the overall costs and revenue requirements** of the utility. This tends to draw the regulator into detailed scrutiny of specific costs rather than considering whether the overall costs are reasonable and efficient and whether revenues are sufficient for a viable utility. That is, it may remove incentives to flexibly manage expenditure and exploit opex substitution possibilities to minimise cost.

The second disadvantage follows on from this. A focus on individual costs inevitably encourages a **tendency towards micro-management and concentration on cost items that are trivial or insignificant**. A regulator only has limited time and resources to review a tariff submission and, therefore, must decide how to prioritise its review. A classic example of how bottom-up assessments can lead to misallocation of resources, seen among many regulators, is a concentration on high-profile but (relatively) low-significance cost items such as management salaries and perks while paying little attention to much larger cost items such as the ongoing costs of network maintenance.

The third disadvantage is the **limited incentives for efficiency** that a focus on individual cost items results in. Often, a utility will seek to reduce costs in one area by increasing costs (by a lesser amount) in another. An obvious example would be the mechanisation of maintenance activities previously undertaken by labour. This would transfer the costs from the maintenance operating costs category to the capital expenditure category. The risk that the utility faces under a bottom-up assessment is that operating costs are reduced to match the new, lower figure, but capital costs are not increased, leaving it worse off.

The last notable disadvantage is the **potential offered to utilities to 'game' the system** under a bottom-up assessment. Utilities have significant discretion, even when applying financial accounting standards, as to where and when to record cost items. An obvious example is which expenditures are capitalised and which are expensed as operating costs. A utility will look to move cost items away from those items on which the regulator might be expected to focus to other cost categories where regulatory scrutiny is lower.

4.1.2 Yardstick assessments

Description

Yardstick assessments relate allowed costs to an external benchmark, over which the regulated utility has no control. We distinguish such assessments from top-down and bottom-up assessments because, as mentioned above, these latter use external benchmarks to *inform* decisions on efficient costs but do not *rely* purely on these, in the way that a yardstick assessment does.

Pure yardstick

Under a pure yardstick, the costs of a regulated utility are set only with reference to the costs of an external benchmark. The use of deterministic benchmarking under pure yardstick regulation is relatively rare. However, even where such estimates are not relied on deterministically, some countries' regulators have sought to partially apply the approach in **setting efficiency and productivity target improvements**. This usually applies for distribution (rather than transmission) networks, and where there are many such companies that can be grouped into those with supposedly similar characteristics and with efficiency factors then being set based on the costs of the group rather than the costs of an individual utility within the group.

Model utility

The use of a 'model' or 'reference' utility approach is also a form of yardstick regulation. Under this, the allowed costs of a utility are based on a set of cost norms derived from other utilities rather than to the utility's own costs.

Crucially, a model utility approach also links allowed capital costs to a set of reference costs rather than using the historical acquisition costs of the utility's assets. This might be done using the existing network but revaluing it using a set of external reference costs or, more drastically, by creating an optimal network without reference to the configuration of the existing network. Capital expenditure allowances are then calculated with respect to the resulting asset base (eg, as an annuity) rather than being determined with respect to proposed investments.

Assessment

Advantages

The main advantage of a yardstick assessment methodology is the **much stronger incentives it creates to improve efficiency**. By decoupling allowed revenues and actual costs, the regulated utility can retain the full benefit of reducing its costs below those of the comparators used to set allowed revenues.

Yardstick regulation also has the advantage of **limiting the need to review the costs of any individual utility in detail**. This can be very valuable where there are large numbers of utilities and may, for example, be one of the drivers behind the reliance on cost benchmarking in countries that have many distributors.

Disadvantages

The main disadvantage of yardstick assessments is the counterpart of its main advantage. Because allowed revenues and costs are decoupled, it is very important that the **comparators used to set allowed revenues operate in similar environments to the regulated utility**. This includes similar institutional, legal and market frameworks, similar cost structures and similar climatic, topographical and demand conditions. Without these similarities, there is a high likelihood that setting allowed revenues based purely on the costs of comparators will lead to excessive profits or losses for the regulated utility, making the revenue control unsustainable.

A corollary of this is that there should be **many comparator utilities** meeting these requirements. Without this, there is a risk that the results will be distorted due to outliers (unusual comparators) or data errors. While these same data issues face the use of top-down assessments (discussed below), they are less serious in this case as they are balanced by also considering the actual costs of the regulated utility.

The other major disadvantage of yardstick assessments, which again is shared with the use of top-down assessments but in amplified form, is the **reduced transparency of the analysis**. Typically, in developing cost estimates, the regulator will make use of statistical tools such as multi-variable regressions and data envelopment analysis (DEA). These are not familiar to most stakeholders and often require the use of proprietary software. In addition, the comparator data used may well be confidential or otherwise not publicly available. This means the regulated utility and stakeholders more generally will find it hard to review or challenge the regulator's analysis, reducing confidence in and acceptance of the regulator's decisions.

4.1.3 Top-down assessments

Description

Top-down assessments abstract from individual cost items and, instead, focus on broad cost categories. They will tend to make much greater use of evidence from external comparators in assessing the efficiency of proposed costs than is the case under a bottom-up assessment. However, they still retain an element of discretion in setting the final total cost.

Assessment

Advantages

Top-down assessments to some extent represent a point between bottom-up assessments and yardstick assessments. They make heavy use of external comparisons to assess the reasonableness and efficiency of a regulated utility's costs. At the same time, they still consider the actual costs of the utility when setting allowed revenues, rather than abstracting from these as under yardstick assessments and, thereby, **attempt to avoid or limit the risk of large divergences between revenues and costs**.

Relative to bottom-up assessments, top-down assessments encourage a focus on the overall revenues relative to costs rather than concentration on a small set of individual cost items. And, by using much larger aggregate cost 'building blocks', they reduce the potential for utilities to switch costs around to manipulate outcomes while also rewarding utilities where increases in one cost line item are more than offset by corresponding reductions in another. They are, therefore, much more likely to deliver **stronger incentives for efficiency improvements as well as to ensure the financial viability of a utility** than a bottom-up assessment.

Disadvantages

The disadvantages of top-down assessments also reflect their position as somewhere between a line-by-line bottom-up assessment of the costs of a regulated utility and setting allowed revenues purely by reference to the costs of comparators, as under yardstick assessments. By relying heavily on external comparisons, a top-down assessment requires **access to a complete and consistent dataset of many similar utilities** for this purpose. The actual analysis itself can also require the use of complex statistical models which **reduce transparency and acceptability** of the outcomes to stakeholders. This is compounded by the **larger use of regulatory discretion** in reaching final outcomes than is typically the case under either bottom-up or yardstick assessments.

4.2 Factoring in productivity improvements over time

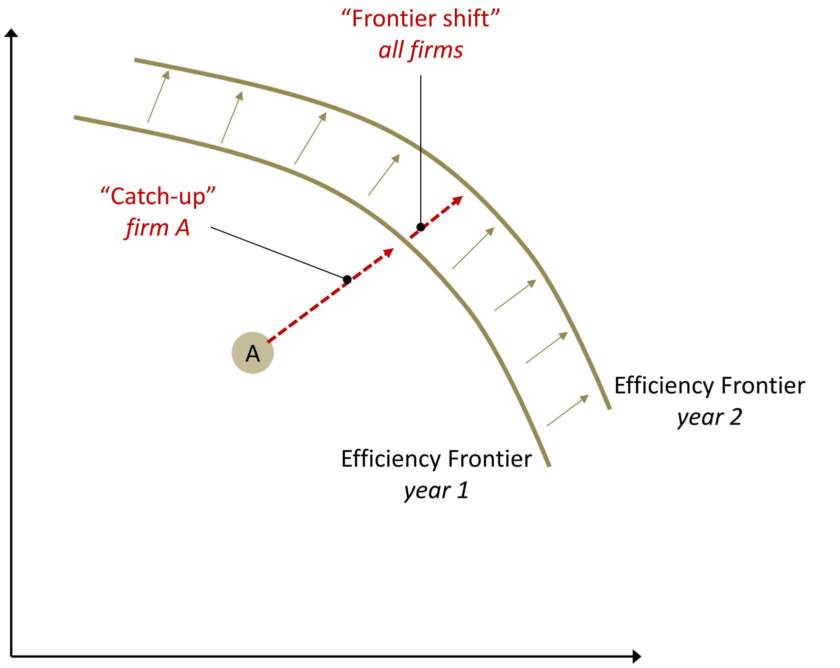
A fundamental objective of regulatory regimes is to ensure that **regulated businesses are compensated only for their efficient costs** (and that they be provided with incentives to pursue efficiencies). The concept of efficiency can be decomposed into two components:

- **Relative efficiency ('catch-up')** – this represents the difference between a firm's current level of efficiency and that represented by the most efficient firms now (defined as those firms lying on the 'efficiency frontier')

- **Productivity growth ('frontier shift')** – this represents the expected movement of the efficiency frontier over time. Even the most efficient firms currently will have scope to continue to improve efficiency over time as innovative technologies and work practices become available.

These two concepts are illustrated in Figure 28 below.

Figure 28 Components of efficiency



Estimating relative efficiencies requires the use of comparator firms, against which the firm under consideration can be benchmarked. Estimating productivity growth can, in principle, be done using only a single firm if a sufficiently long time series of data is available (and if the firm is assumed to already be at the efficiency frontier).

There is extensive academic literature as well as practical experience in benchmarking the cost efficiency of regulated utilities[19]. The sophistication of benchmarking models has greatly developed over time, as has an understanding of how to use these. Nevertheless, few regulators use benchmarking alone to set price controls. However, **regulators generally either use the results from benchmarking as a form of 'challenge' to regulated utilities, which are asked to demonstrate why the results should not be applied, or use them as just one piece of information** among many.

This reluctance to rely solely on benchmarking reflects the limited reliability of the results. This lack of reliability in turn derives from the lack of consistent data for an adequate number of comparators. As an approximate rule of thumb, at least 40+ data points are needed for the results of an econometric analysis to be reliable. To estimate annual efficiency improvements, for example, this would imply a need for 40 years of data for a single utility or for eight years of data if using five comparator utilities.

Even if international data can be obtained, there are still very significant issues in ensuring consistency. Different utilities may well classify expenditures such as maintenance and renewals in diverse ways. There is the question of what exchange rates to use in converting across countries. And there is also a need to consider the relative labour and capital costs. A country with high wage costs would generally use fewer staff and more capital equipment

[19] For example, a 2012 survey of 25 regulatory agencies in Europe, Latin America and Australasia found that 13 used some form of benchmarking to regulate transmission companies. (Haney A and M Pollitt, 2012, *International Benchmarking of Electricity Transmission by Regulators: Theory and Practice*. EPRG Working Paper #1226).

than one with low wage costs, so that comparing staffing numbers or costs across the two would give a misleading impression of relative efficiencies.

Notwithstanding these caveats, **it is generally considered important for regulators to use their judgement to determine the scope for the businesses to achieve efficiency improvements over time** and ensure that these are factored into the cost allowances.

4.3 Analytical methods for assessing costs and efficiency

There are several analytical methods employed by regulators (and/or required of the businesses) when assessing (claiming) the reasonableness of forecasted expenditure. The choice of analytical technique generally depends on the nature of the expenditure category being assessed and several methods are used in combination to obtain a holistic view of the total capital and operating expenditure forecasts – that is, the analytical tools are not mutually exclusive, and some regulators do consider the interconnections between the assessment techniques employed when determining the reasonableness of the businesses' forecasts. Some analytical tools commonly used include:

- Trend analysis
- Methodology assessment
- Detailed project review
- Predictive modelling
- Business case analysis
- Examination of governance practices
- Statistical (cost) benchmarking.

Each of these techniques is briefly described in the sub-Sections that follow.

4.3.1 Trend analysis

This technique entails using trends in **historical time series data** for specific cost items to detect general patterns and the relationship between associated factors or drivers, and on this basis project the future direction of the pattern (and therefore the relevant costs).

Trend analysis can be particularly helpful for assessing operating expenditure (and detecting step changes in costs, which might require further investigation and justification by the businesses). However, trend analysis may also be useful for capital expenditure assessments where expenditure categories display relatively consistent levels of expenditure over time.

4.3.2 Methodology assessment

Beyond the cost forecasts themselves, some regulators find it important to also understand the **analysis underpinning the cost information** and specifically, the models used and the related **inputs, assumptions and methodologies**. Regulators can therefore assess the reasonableness of the methodology employed by the regulated utilities and whether it forms a robust basis for developing expenditure forecasts.

Where this approach is employed, regulators generally can seek explanations and justifications of the forecasting methodology employed by the utility and the results produced, and to seek further justification when the methodologies (or aspects of them) do not appear to be reasonable. Where the regulator is not satisfied with the further explanation, it can seek adjustments to the methodology such that it forms a reasonable basis for developing expenditure forecasts that are robust and economically justified (by which is meant the minimisation of the long-run costs).

4.3.3 Detailed project review

In some cases, regulators might find it necessary to undertake a **more detailed review of specific project or programme expenditure**. This would normally be the case:

- If one of the other analytical techniques has revealed some notable change from historical costs and therefore further scrutiny is required, or
- If it is new expenditure where historical information is limited or irrelevant, or is highly specialised and /or non-recurrent expenditure, or
- As part of a random review of certain expenditure categories so that the regulator obtains greater assurance of the validity and reliability of the cost forecasts.

Such detailed reviews would normally focus on specialised technical areas (for example, augmentation needs given demand forecasts and available network capacity) and would often entail engineering reviews that would typically be undertaken with the assistance of subject matters experts (usually engineers that have some specialisation in the particular area).

4.3.4 Predictive modelling

This entails the use of statistical and econometric modelling and analytical techniques to determine the expected pattern of efficient costs over the forthcoming revenue control period for specific **categories** of works or expenditure. In simple terms, the process entails capturing multiple predictors into a model, which when subjected to analysis can be used to forecast future expenditure with an acceptable level of reliability. This typically entails gathering data, formulating a statistical (usually, regression) model and making predictions, and validating and/or revising the model as additional data becomes available. An important prerequisite for adopting this approach is to have very good data.

4.3.5 Business case analysis

Under this approach, the cost submissions of the gas transmission businesses must necessarily be underpinned by economic justification, that is, the businesses should be required to demonstrate (in a quantitatively-based manner) that the forecast expenditure is expected to be **the lowest cost option in the long run relative to other feasible options in net present value terms**. This is like cost-benefit analysis (or other similarly termed analysis such as financial justification, return on investment analysis, etc). The fundamental requirement is that the chosen expenditure must be demonstrably superior to other options; to make the business case, the submissions must contain relevant information about the background to the proposed expenditure (typically this is set out in asset management plans), the expected benefits, the options considered (with reasons for rejecting or proposing each option), the expected costs of the project, and the expected risks. Any such analysis would generally be focused on expenditure decisions for groups of assets or individual projects that materially affect forecast expenditure.

4.3.6 Examination of governance practices

Some regulators also seek information on the **internal processes employed by the utilities to assess needs and to underpin the business case** for the specified expenditure. These processes would include strategic planning practices, risk management techniques, asset management policies, and procurement rules and practices. A review of governance practices does not of itself inform whether the cost estimates and forecasts are reasonable; however, the review may highlight that the cost forecasts are not based on sound governance arrangements which could then imply that overall efficiency and cost estimation is not robust and therefore further analysis based on the other techniques discussed above may be required.

4.3.7 Statistical (cost) benchmarking

Statistical benchmarking encompasses many different methods for establishing the efficient costs of the regulated businesses and encouraging them to achieve the long-run efficiency outcomes normally associated with workably competitive markets. More specifically, cost benchmarking covers any of several 'static' or 'dynamic' methodologies that compare a regulated company (or aspects of its costs) to:

- Other regulated businesses in the same or similar sectors, and/or
- Itself (or between its various divisions) over time, and/or
- An 'ideal' regulated firm.

Most cost benchmarking analysis focuses on productive or technical efficiency (ie achieving the maximum possible output from a given set of inputs) and is also normally used in incentive-based regulatory frameworks to encourage other aspects of efficiency, namely allocative efficiency (ie setting revenues and tariffs equal to efficient costs) and dynamic efficiency (ie maximising the potential for increasing efficiency over time). In simple terms, the incentive mechanism employed entails calculating some measure of efficient costs of the regulated business using benchmarking (after controlling for factors not influenced by the business) and allowing the business to set tariffs to recover the efficient (benchmarked) costs.

There are a number of benchmarking techniques that are used to establish efficient costs:

- **Parametric cost estimation methods** – these provide estimates of parameters of a production or cost function using statistical relationships between historical costs and relevant outputs or outcomes, and using information about the inherent imprecision of those parameters eg ordinary least squares (OLS) analysis, corrected OLS and stochastic frontier analysis (SFA)
- **Non-parametric cost estimation methods** – these methods do not employ any assumptions about the distribution of the sample or population data and include approaches such as partial productivity indicators, total factor productivity indices and data envelopment analysis (DEA)
- **Hybrids** combining the parametric and non-parametric methods
- **Engineering models** – these are 'bottom-up' models and entail detailed cost estimates about the efficient costs of constructing and operating networks based usually on expert engineering knowledge and opinion.

While the literature and empirical work on benchmarking is extensive, there is no consensus in the academic literature or among regulatory practitioners about the best or most appropriate benchmarking techniques (or indeed about the appropriate inputs and outputs of the various models and measures).

4.4 Capital expenditure reviews

The assessment of capital expenditure raises special challenges and, in many regimes, requires consideration of the different categories (and drivers) of expenditure on a transmission network, which typically comprise:

- Refurbishment or replacement of specific network segments
- Extension and reinforcement of the network
- The provision of new customer connections and metering
- Other capex, such as the installation of any new information systems.

We address each of these cost categories in turn.

4.4.1 Refurbishment and replacement

Refurbishment and replacement expenditure is typically incurred to address the **deterioration of existing assets**. This includes works driven by measured or observed reductions in reliability or other quality parameters and as a result of an assessment of increasing risk of system/network failure or of insufficient levels of reliability and quality.

This type of expenditure is closely related to (or can be substituted by) maintenance opex, so regulators sometimes require utilities to identify and **explain potential expenditure and efficiency trade-offs** between the two expenditure categories.

In assessing the reasonableness of the business's cost submissions in this area, regulators could employ the following methods:

- Analysis of the **information** submitted by the utility **to support** the claimed refurbishment / replacement capital expenditure, such as condition and risk assessments, and safety, reliability and performance information
- Comparison of forecast capex with **historical expenditure** by the utility for this purpose
- Detailed **project** and engineering **reviews**
- **Modelling** of refurbishment and replacement expenditure.

4.4.2 Network extension and reinforcement

Network extension and reinforcement is typically required by a need **to build or augment network assets to address changes in demand** for transmission network services **or to maintain and/or improve the quality, reliability and security of supply** in accordance with legislative and regulatory requirements. To avoid double counting, it is important to distinctly classify extension and replacement capital expenditures. Generally, asset replacement driven by economic condition is classed as replacement capex for the purposes of expenditure reporting and forecast assessment. This applies irrespective of any upgrade to the asset that may be undertaken when assets are replaced at the end of their economic lives.

Assessment of network extension and reinforcement capital expenditure would typically involve (among other things):

- Examination of the business's capital projects **governance framework**, including investigation of how the augmentation expenditure relates to the system and network development plans
- Investigation of the augmentation **forecasting methodology** and particularly the methodology, assumptions, inputs and calculations for projecting **demand**
- Examination of the **relationship between the demand forecasts and the proposed projects and programmes**, including investigation of the options considered to meet the forecast demand (inclusive of non-network alternatives and demand-side participation) and the network constraints that require rectification due to demand increases (including those related to capacity)
- Detailed **technical reviews** of specific projects
- **Modelling** of various cost measures for distinct types of augmentation projects.

4.4.3 New connections and metering

Customer-initiated connection works to the gas transmission system are generally infrequent and when they occur are very specific to the needs of the particular industrial user(s) of gas. Hence, under such circumstances cost assessment would necessarily rely on **reviewing the specific connection works with the assistance of technical consultants (if needed) to undertake a detailed project review**.

Over time, where there are more frequent connections to the transmission system, regulators could assess whether there would be value in obtaining standardised information that would permit the use of trend analysis or other techniques to assess expenditure related to transmission customer connection projects.

4.4.4 Other capital expenditure

Other capital expenditures will generally relate to activities that are indirectly associated with the transmission networks (and are not captured by the previous cost categories or drivers). Regulators can assess such miscellaneous expenditure by disaggregating it into typical subcategories such as the following:

- IT and communications (including SCADA and network control systems)
- Vehicles
- Plant and equipment
- Buildings and property
- Other.

In this case, regulators can **assess other expenditure that is more recurrent separately** to less recurrent expenditure – the former could then be assessed by looking at revealed costs in the past and employing the techniques discussed earlier (trend analysis, predictive modelling, etc). Some regulators also examine total expenditure (capital and operating expenditure combined) when assessing different categories of 'other' capex.

4.5 TOTEX approaches

Much of the foregoing discussion has assumed that operating and capital expenditures are separately treated for the purposes of regulators assessing their reasonableness or efficiency and for then setting allowed revenues accordingly. This indeed has been the typical 'building block' approach applied by most, although not all, regulators in the EU (and elsewhere). However, some regulators have moved away from this approach (or adopted a different approach from the outset) entailing the determination of revenue allowances by **combining operating and capital expenditures or, put differently, by assessing total expenditure ('TOTEX')**. Three key considerations motivating the use of a TOTEX approach include:

- **Removal of the 'capex bias'** – it is generally felt that building block approaches favour capital expenditure solutions (eg asset replacement) over opex (ongoing maintenance), as the former would provide a steady stream of profits over the assumed life of the assets. This bias is more pronounced where there is an incentive mechanism applied to opex underspending (as the firm also retains the savings on opex, or a portion of them, as a reward for its outperformance).

- **Potential gaming by the regulated firm** - the conventional building block approach may also provide a perverse incentive to reclassify opex as capex – a regulated firm, for example, would gain by having a category of expenditure recognised as opex when setting allowances and then changing its capitalisation policy within the regulatory period to reclassify the expense as capital expenditure.

- **Business flexibility for efficient delivery of services** – under a totex approach the regulator adopts a neutral view about whether operating or capital expenditures should be incurred, which should then encourage the regulated businesses to choose the mix of expenditure that is most consistent with long-term efficiency.

Regulatory frameworks employing totex approaches **rely heavily on statistical benchmarking techniques** for establishing the cost of service (see Section 4.3.7). There is generally no reference to separate operating and capital expenditure allowances, nor any reference to the historical costs of the regulated business. In some cases, it is also unnecessary to roll any investments into a regulatory asset base (RAB), although regulators employing this approach would need to ensure that the benchmark method relates to the long-run marginal costs of supplying services (thereby minimising the risk of future asset stranding).

5 The regulatory asset base

A core feature of gas transmission businesses is that they are capital intensive. The network assets are economically sunk costs with practically no alternative use. They require continuing investment to maintain and extend their service capabilities and adapt to changing patterns of demand and supply. To secure finance, it is necessary to create the conditions for owners, lenders and service providers to be confident that the business will be able to sustain high enough revenues to remunerate that finance.

The concept of the regulatory asset base (RAB), which is universally applied in Europe, provides the foundation for this confidence, as it is effectively an expression of regulatory commitment regarding the basis of remunerating finance. The design of the mechanisms and safeguards surrounding the RAB is therefore critically important as it provides the conditions for effective investment incentives and a low cost of capital (and hence gas transmission tariffs).

There are several important questions to consider from a methodological perspective regarding the RAB. Some of these, which form the focus of the rest of this Section are the following:

1. How should the opening asset value be set (at the beginning of establishing the RAB-based framework)?
2. When and how to include new assets in the RAB?
3. Whether and how to update the value of the RAB over time?
4. How should the RAB be depreciated?
5. Whether and how working capital should be included in the RAB?

5.1 Setting an opening asset value

The value of existing assets is fundamental to the determination of allowed revenues because both depreciation and return on capital are calculated from it.

There is a wide range of asset valuation methodologies, but there is no single approach that is appropriate in all circumstances. Our broad categorisation and description of these methodologies (drawing on the literature review material) is as follows:

- **Historical cost accounting methods** – based on the cost of acquiring and renewing assets in the past less the cumulative depreciation on those assets. Where networks have old assets that have been maintained and can be kept in good condition for extended periods into the future, historical cost accounting methods that depend on finite lives may have little relevance to the economics of transmission charging. This method also depends on accurate historical cost information being available.

- **Replacement cost methods** – based on the cost that would be involved in replacing the service capability of the existing assets, taking account of the cost of replacing their service capability were it to be replaced now and adjusting for depreciation to reflect the remaining useful lives of the assets. These methods are most commonly used to value privately owned transmission businesses. However, replacement cost valuations are often more than any practical measure of the value in use and are therefore subject to impairment adjustments to bring them in to line with a value in use measure.

- **Current (economic) value method** – based on the 'value in use', which reflects the present value of future net cash flows that can be expected from the operation of and services provided by those assets. The conceptual problem with a value in use methodology for revenue setting is that the assessment becomes circular – the value in use is itself driven by the anticipated level of revenue.

Because investments in the existing asset base are effectively sunk costs, there is no clear economic rationale for using historical cost accounting methods rather than replacement cost methods or vice versa. In many cases, therefore, regulators use a value that rolls forward directly from the value used in previous decisions, or a value that reflects any explicit, implied or perceived regulatory commitment in previous decisions, or a value that, moving forward, keeps the balance of interests between network users and service providers broadly stable but that remedies any widely perceived current inequity in the balance of interests between them (note than in an established regime, these criteria will coincide).

From an economic perspective, the critical point is not necessarily how the opening asset base is set (although obviously this will be important for network users), but that it continues to be clearly recorded and that it be updated in a consistent manner going forward. This provides investors in the utility confidence that their costs will be recovered, and therefore reduces the cost of finance (and the future cost of service provision).

5.2 Inclusion of assets in the RAB

5.2.1 Expenditure assessments and deviations between regulatory and accounting statements

Financial statements show physical assets at their actual purchase price (capital expenditures). The statements distinguish between work in progress and assets that have been commissioned and are in service.

Including assets into the RAB at their actual cost does not, of course, create incentives for utilities to invest efficiently. Regulators, therefore, may subject proposed investments to reviews of their need and costs before approving them for inclusion in the RAB (thereby allowing their costs to be recovered). This may be done on an *ex-ante* basis, with the value of the investment for inclusion in the RAB being set in advance, or *ex-post*, when the investment has been made and the regulator reviews the reasonableness of the costs before adding them to the RAB (for revenue setting purposes).

Because of such reviews, the values of assets in the RAB (which determines the costs that can be recovered) and in the audited financial statements may differ (as they can for other reasons too). This is not necessarily a problem—such a difference between the values used in regulatory and financial accounts is reasonably common.

5.2.2 Timing of asset inclusion in the RAB

A key issue that also arises in this regard is when should the capital expenditures be included in the RAB – as incurred, or when a project is commissioned (with the total value grossed up to account for returns on the asset during construction)? Both approaches have largely the same effect on the incentives of the utility because (assuming the total value is grossed up for returns during construction using the allowed WACC) both are equivalent in present value terms.

The key advantage of adding capital expenditure when it is incurred is that it is easier to administer because there are no complexities related to capital expenditure being incurred in one regulatory period but not commissioned until the next. The key disadvantage is that users may pay for capital expenditure that is not yet operational and will not be for some years ahead (thereby distorting allocative efficiency). This effect can be significant for large assets with long construction periods, which characterise many of the investments in gas transmission. On the other hand, including such large investments only once they are commissioned can create financing difficulties for the utility. There is no consensus among regulators on the 'best' approach. In general, the approach is that major investments are funded on a pay-as-you-go basis (ie, capital expenditure is included as incurred) to help financing of these projects. Smaller-scale projects can be managed on either basis. But there are many deviations from this.

Where new investments are added to the RAB once they are commissioned, a decision is also needed on how financing costs during the construction period should be considered. As mentioned above, an approach that employs the allowed rate of return for grossing up the value of the asset retains investment incentives intact. However, some regulators employ the cost of debt for assets during construction (or other indices, such as an inflation index). It is not clear what the rationale for such approaches is, other than adhering (in the case of using debt costs) to accounting convention which requires debt costs during construction to be capitalised.

From an economic perspective, however, grossing up investments with rates lower than the cost of capital could send incorrect signals. The implementation of a capital expenditure programme is a typical 'equity activity' in that capital projects require active management of risks related to construction, engineering, and cost and schedule variability. Capitalising assets therefore using just the cost of debt (or inflation) would undercompensate the capital projects and could therefore lead to less than optimal investment.

5.3 Revaluation of the RAB

Over time, the historical purchase or construction price of assets will deviate from their replacement cost[20]. In most cases, but not always, replacement costs will exceed the

[20] This discussion considers whether revaluation to match the replacement cost of assets is desirable for regulatory purposes. It is separate from the mechanics of calculating allowed returns where

historical cost. It may also be that the actual configuration of assets is no longer (or never was) optimal to meet demand, meaning that customers are paying for assets that are not required to provide the given service. This opens the question of whether to:

- Require that the RAB used in setting tariffs be revalued at regular intervals to reflect their current or replacement costs (including, potentially, optimisation of the asset base against requirements), according to rules established by the regulator
- For regulatory purposes, not allow any revaluation of assets to be passed into tariffs
- Allow the utilities to revalue assets in their financial statements according to their own methodologies and to then use these new values as the RAB going forward.

An implication of the first and second options is that these will lead to the RAB used for regulatory purposes diverging from the asset values in the audited financial statements of the utility. However, this should not be a problem as it is generally now accepted by regulatory authorities that statutory accounting frameworks and conventional accounting values will diverge from the value of the RAB and the criteria for effective economic regulation underpinning that value.

5.3.1 Arguments for and against current cost / replacement valuations

The arguments made for regulatory revaluations of assets generally revolve around the resulting improvements in economic efficiency and, in particular, of delivering tariffs that better reflect the 'true' costs of service. They include:

- Setting prices based on the current or replacement costs of assets **ensures that sufficient financial provision is being made (through the depreciation allowance) to replace existing assets** as they are retired. It, therefore, ensures that current users are paying a 'fair' share of the costs of consuming these assets rather than loading these onto future users.
- The replacement costs of assets reflect the market value of the capital tied up in these assets. Therefore, prices calculated using replacement costs **better capture the opportunity cost to the economy** of providing the associated service (in this case, gas transmission) and, thereby, lead to more efficient resource allocation decisions[21].
- Where utilities face potential competition from new entrants, setting their prices using the current or replacement costs of assets ensures that **the resulting**

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regulatory agencies may choose to set WACC in real terms (ie, excluding inflation) and to then compensate for the impacts of inflation by uprating the RAB by an inflation index.

[21] To illustrate, assume that the historical cost of the asset base is €100 million, the replacement or current cost is €200 million, and the cost of capital is 10%. If the historical cost is used in setting regulated charges then users are effectively paying only half of the cost (10% * 100 million compared to 10% * 200 million with revaluation) associated with tying up capital in gas transmission rather than reallocating it to other, potentially higher-value, uses in the economy.

regulated prices are comparable to those of competitors, helping promote entry on equal terms (a policy of 'competitive neutrality').

The validity of the arguments for current or replacement cost valuations for utilities have been questioned by some practitioners. In particular, regulated network businesses generally do not face a competitive threat (which is why they are regulated) and so it is not clear that this is a strong argument for revaluations of assets. The concept of reflecting the opportunity cost of assets is also questionable given there is limited scope in most cases to redeploy existing gas network assets[22].

The arguments against such revaluations are:

- They can deliver **'windfall' gains or losses to the owners of the utility**, unless these are compensated for through offsetting reductions or increases in allowed revenues. An upwards revaluation increases the deprecation and allowed return earned without any corresponding increase in debt service costs or requirements to inject more equity capital. A downwards revision has the reverse effect.
- Depending on the revaluation methodology adopted, they can **create significant uncertainty and risk for utilities over the future value of the RAB** and, therefore, whether they will be able to fully recover their investment costs. This will need to be compensated through a higher return. Including an optimisation of the asset base in any revaluation is particularly subject to this risk, as this means that external consultants with the benefit of hindsight are deciding whether the current assets are required or not, with the utility having little control over this.

5.3.2 Alternative revaluation methodologies

Where assets are revalued at current or replacement costs, a range of alternative methodologies can be applied. At their simplest, asset values can be indexed to an inflation measure. More complex is to revalue assets at the cost of replacing them with a modern asset. The most complex is to optimise the value of the assets by looking at the services that existing assets provide and to then determine the least-cost means of providing the same services using a set of modern assets. This may include removing existing assets from the asset base where they are not required to meet demand or reducing their size where capacity exceeds requirements.

The various alternatives and their advantages and disadvantages are summarised below.

[22] One response to this criticism is to set the RAB at the scrap value of the associated assets—which is what could be realised if they were all sold. However, this is generally far below the replacement or historical cost meaning significant losses are imposed on asset owners. Also, it is questionable whether scrapping the gas transmission network as a whole is at all realistic.

Figure 29 Replacement cost valuation methodologies

Inflation Index

Historical cost is multiplied by the change in a general inflation index (e.g. CPI)

Advantages

- Simple to apply

Disadvantages

- Asset costs are unlikely to change in line with general inflation

Like-for-Like Replacement

Current market price of purchasing the same asset

Advantages

- Avoids disputes over what asset to use when estimating current costs

Disadvantages

- Many older assets may no longer be produced, meaning no market price is available

Modern Equivalent Asset

Current market price of purchasing a new asset that has the same capabilities

Advantages

- Ensures that a market price is available

Disadvantages

- Disputes over what is the modern equivalent to many older assets

Optimised Modern Equivalent Asset

Current market price of purchasing a new asset that delivers the same services

Advantages

- Reflects the current value of the asset to users

Disadvantages

- Disputes over optimisation, increased risk to asset owners that they cannot recover their costs

5.4 Depreciation of the RAB

The use of depreciation to determine allowed revenues is intended to spread the costs of investments out across their useful lives. Theoretically, an alternative approach would be to allow the utility to fully recover the costs of its capital expenditure in the year in which it occurs, but this would place the full cost burden on customers in that year, when in fact the investment is likely to benefit both present and future customers for many years to come.

Because it is important that depreciation reflect the costs of investments across their useful lives, economic asset lives are generally used rather than accounting asset lives. Accounting lives are generally set for constructing statutory financial accounts and for tax reasons and, in the past, might have borne little resemblance to the actual useful lives of assets. However, with the adoption of IFRS, there is generally greater alignment between the two given that the accounting standards require that, “The depreciation method used should reflect the pattern in which the asset's **economic benefits** are consumed by the entity" (IAS 16.60, emphasis added).

There are various options for the depreciation life and profile applied including straight-line depreciation, a declining balance and sculpted profiles. These give different rates of recovery of the costs of the asset and, therefore, of the timing of revenues from it. Alternatively, an annuity can be calculated which gives a constant revenue allowance for each year of the asset's life, the total value of which is equal to the sum of allowed depreciation and returns.

In addition, assets might be depreciated according to depreciation schedules associated with the type of asset category to which an individual asset belongs, or once assets have entered the RAB they may be treated as being a single 'lump', that is depreciated using an average weighted asset life. We note that the latter also makes removing any capital expenditure that is disallowed (on efficiency and prudency grounds) by the regulator straightforward — one simply deducts this from the RAB value with no need to try and break it down by project or asset type to depreciate using asset categories. But it does mean one cannot reconcile the resulting values back to the asset register used for the audited financial statements of the utility.

We note that in some regimes (eg North America), such discrepancies between accounting and regulatory treatments and statements do not arise in the first place. This is because the audited statements assign a zero value to an asset on which the regulator does not allow the regulated entity to earn depreciation and a return. Our understanding is that this approach is underpinned by a requirement under IFRS for assets recognised in the balance sheet to embody 'a future economic benefit' (which in the case of regulated entities amounts to the revenues and tariffs allowed by the regulator). For example:

1. In the USA, the relevant accounting standard under GAAP (generally accepted accounting principles) states that, "*When it becomes probable that part of the cost of a recently completed plant will be disallowed for rate-making purposes and a reasonable estimate of the amount of the disallowance can be made, the estimated amount of the probable disallowance shall be deducted from the reported cost of the plant and recognized as a loss. If part of the cost is explicitly, but indirectly, disallowed (for example, by an explicit disallowance of return on investment on a portion of the plant), an equivalent amount of cost shall be deducted from the reported cost of the plant and recognized as a loss*". The relevant standard can be found here: http://www.fasb.org/cs/BlobServer?blobcol=urldata&blobtable=MungoBlobs&blobkey=id&blobwhere=1175820928821&blobheader=application%2Fpdf

2. In Ontario, Canada, the accounting standards for regulated utilities include the following statement: "*The Board requires utilities to adhere to IFRS capitalization accounting requirements for regulatory reporting and rate-making purposes after the date of adoption of IFRS. It should be noted that in determining the cost of property, plant and equipment and intangible assets to be included in the rate base, where the proposed cost is, in the opinion of the Board, not reasonable for inclusion in the rate base, the Board can make its own determination of the cost to be included in rate base*" (see top of p 315 in https://www.oeb.ca/oeb/_Documents/Regulatory/Accounting_Procedures_Handbook_Elec_Distributors.pdf).

5.5 The treatment of working capital

Working capital can be described as the average net amount of capital employed in the firm which is not invested in long term assets but in various short-term items, such as cash and inventories, and which is required for the day-to-day operations of the firm. Where working capital is funded from equity or debt, then this represents a commitment by the owner which should in theory be remunerated. Where it is funded by accumulating payables then, in effect, it is funded by external third parties. Hence, working capital, properly calculated, is likely to be a legitimate cost of conducting the regulated business.

There is no single 'correct' way of calculating working capital as a regulator. The purpose of the calculation is generally to arrive at something reasonable and acceptable to the regulated business, and which is not so time consuming that the costs of calculation exceed the benefits. The accounting definition of working capital is clear—working capital is the difference between current assets and current liabilities. However, regulators prefer to define working capital based on some measure of the funds that need to be held to cover gaps between cash being received and paid. This is rather different to the accounting approach. Examples of such alternative computation measures used by regulators include:

❑ **Lead-lag study** – this determines the average time difference between when expenses must be paid ('expense lead') and when revenue is collected ('revenue lag'), expressed in days. The days so derived multiplied by the average daily operating expenses yields the working capital required for operations.

❑ **Formula (45 days) approach** – the Federal Energy Regulatory Commission and several other State Commissions in the US determine the working capital allowance based on the 45-day convention, which allows a utility a cash working capital allowance equal to one-eighth (one eighth of a year equals about 45 days) of the business's annual operating and maintenance expenses.

❑ **Simplified approaches** – in some jurisdictions, a fixed percentage of allowed revenues or invested capital/net assets is used.

Regarding the rate that should be used for remunerating working capital, the main options are to either use the allowed WACC or a short term borrowing rate. When using the WACC, the presumption is that working capital should not be treated any differently from other aspects of capital employed and that therefore any working capital is financed by investors through a combination of debt and equity finance. This would be equivalent to assuming the owner of the entity injects a sum of money as working capital which is then left in the businesses permanently.

However, this does not accord with the normal operations of regulated (or other) businesses. Short-term operational needs are generally met through short-term borrowings and equity capital is reserved for investment in long-term assets. Even in unexpected circumstances (such as a cost shock) which might create a 'peak' working capital requirement, this would generally be financed through cash or credit facilities available to the regulated business (rather than raising equity capital), or other contingent facilities such as letters of credit.

Accordingly, a short-term borrowing rate is commonly adopted by regulators for remunerating working capital.

6 Cost of capital and financeability

A fundamental element of any revenue determination is the setting of the allowed or target return on capital, which is the return required by debt and equity holders to finance the investment in capital assets. This return applies both to the existing asset base (to which an explicit value must be ascribed) and new (prudent and efficient) capital expenditure or assets, both of which are enshrined in the regulatory asset base or RAB, as discussed in the previous Section.

The return is generally given by the weighted average cost of capital, or WACC, but an alternative would be to multiply the cost of debt by the value of debt and the cost of equity by the value of equity and adding the two results. The two approaches are algebraically equivalent, and the more meaningful issues are around the estimation and computation of the various parameters of return. The discussion that follows is structured around the WACC concept and its various components, although it is recognised that some regulatory regimes separately treat the cost of debt and the return on equity. The final sub-Section addresses financing tests that are sometimes employed by regulators to ensure investment programmes can be funded (notwithstanding the setting of an efficient and reasonable rate of return).

6.1 The WACC concept

The WACC considers the two components of the cost of capital, the cost of debt and the cost of equity, and is calculated by taking the weighted average of the two, weighted by the relative importance of each type of financing in a company's capital structure. The generic formula for the WACC is as follows:

$$WACC = g \times CoD + (1 - g) \times CoE$$

Where:

g is the gearing level (or the proportion of debt in the capital structure)
CoD is the cost of debt
CoE is the cost of equity.

6.1.1 WACC calculation and tax treatment

There are three different approaches to computing the WACC (depending on where in the revenue calculation tax is factored in, since profit is taxed while interest is tax deductible):

- **Pre-tax WACC** – under this approach a pre-tax cost of equity percentage must be determined that incorporates both the rate of profit reasonably expected by shareholders (after tax) and the level of tax on that profit. Mathematically, this requires multiplying the after-tax cost of equity by the factor 1/(1 - t), the 'tax wedge'.

- **Vanilla WACC** – this computation does not apply the tax wedge and therefore allows for a post-tax cost of equity (and thus a post-tax WACC) but requires that a separate allowance be made for tax on profits as a separate amount in the composition of the required revenues.

- **Post-tax WACC** – with this method, the cost of debt is multiplied by the factor (1 – t) to capture the tax benefit associated with gearing (as interest is deducted before tax is calculated). When using this approach, care is needed in calculating tax allowances, as the tax deductibility of interest costs is already captured in the WACC formula (ie interest costs should therefore be excluded from the calculation of the tax building block of the revenue equation).

6.1.2 Real or nominal WACC

One fundamental design issue regarding the WACC is whether to set it in real or nominal terms - a nominal return includes inflation whereas a real return excludes inflation. The key is to be consistent, ensuring that the utility is compensated for inflation but is only compensated once. If the asset base is indexed to inflation, then the WACC should be set in real terms (ie it should exclude inflation). If the asset base is calculated using historical/ nominal costs, then the WACC should be in nominal terms (ie it should include inflation).

Although the approaches are broadly considered consistent (ie both should result in the same net present value of cash flows), there are some crucial differences. For example, given that debt is paid in nominal terms with no indexation of the principal, this means interest costs have a 'front-end loaded' profile (assuming positive inflation). However, a real regime results in a relatively 'back-end loaded' profile so, using indexing and a real WACC may result in a misalignment between costs being incurred and revenues provided – hence, the need in such regimes for financeability tests.

Under a real regime, there is also the question of what measure of inflation is appropriate to use. In principle, the chosen index should be one that reflects the likely increases in prices faced by the utility, as well as being transparent and practical to implement. In practice, however, it is difficult and contentious to develop a weighted cost index that reflects cost pressures on the wages, materials and other input costs of the utility. For this reason, regulators generally prefer to use a broad-based index that is free of interpretation and entirely outside of the control of the regulated entities such as the Consumer Price Index (CPI). As far as we are aware, international experience seems to favour the use of CPI, although some countries choose to exclude certain categories of cost from the index.

6.1.3 WACC estimation techniques

Generally, there are three main approaches to estimating the WACC:

- **Direct estimation of the relevant business's cost of capital** – this is most obviously possible for the cost of debt where the embedded cost can be determined from company financial information while the cost of new debt can be estimated, for example, from existing yields (where debt is traded), together with expected trends in interest rates.

- **Direct estimation of the cost of capital of comparator companies** – this might be necessary where there is insufficient information for the regulated businesses concerned. It might also be relevant for regulatory regimes that seek to provide incentives for regulated entities to incur the costs of an 'efficient company'. It may also be used in combination with model-based estimates (see below) for the calculation of certain parameters, such as the beta calculation, where again information is not readily available for the companies in question.

- **Model-based estimation** – models are simplified representations of the workings of capital markets and can be useful in providing insights where information is either lacking or inherently unobtainable, or to provide additional relevant data. Models are generally employed for the estimation of the cost of equity, given that there is direct data available for computing the cost of debt.

6.2 Cost of equity – the Capital Asset Pricing Model

In estimating the cost of equity, the fundamental question to be addressed is, what rate of return would be necessary to attract equity finance? For this purpose, most regulators (outside North America) adopt the Capital Asset Pricing Model (CAPM) to address this question[23].

The central tenet of CAPM is that the main explanatory factor for the rates of return implicit in market valuations is an asset's (perceived) sensitivity to systematic risk (also known as non-diversifiable risk or market risk). The level of systematic risk is represented by a number referred to as beta (β). The standard CAPM formula for the minimum expected rate of return (after taxes) on an investment ($r_{expected}$) that would make the investment attractive to investors is:

$$r_{expected} = RFR + MRP \cdot \beta_{investment}$$

In this formula:

- The RFR is the risk-free rate, the rate of return that would be available from a risk-free investment
- The MRP is the market risk premium, the additional return (over the risk-free rate) that can be expected from a balanced portfolio of investments in an investment market (sometimes also referred to as the Equity Risk Premium, or ERP)
- $\beta_{investment}$ is the exposure to market risk in the investment, the extent to which the investment's returns and the returns from the wider market are expected to co-vary (ie vary in sympathy).

The theory applies to any investment asset, but is most useful when thinking about the cost of equity (CoE), post-tax, with reference to an equity beta:

$$CoE_{post-tax} = RFR + MRP \cdot \beta_{equity}$$

[23] Other approaches include the Dividend Growth Model (DGM), which is commonly used in the US and as a cross-check in other jurisdictions, Multi-Factor Models and Surveys of investors and analysts.

Each of these variables needs to be estimated, and it is probably fair to say they are all contentious.

6.2.1 The risk-free rate

The risk-free rate is the return an investor would expect to receive from an investment with zero risk (over a given period). As there are no risk-free assets on which to measure return, the RFR is typically proxied by the yield on government-backed securities in mature markets, which have a negligible chance of default. As the WACC is a forward-looking concept, regulators also sometimes consider future changes as given by forward yield curves on these same government bonds.

In principle, *real* bill and bond returns are most relevant because equity valuations are denominated in real terms (the underlying value of business assets will increase in nominal terms with inflation). A problem, however, with relying on historical assessments of real returns on bills and bonds for setting the RFR is that such returns have not been stable. This is because bills and bonds are denominated in nominal terms. The existence of inflation uncertainty therefore means that *ex post* measures of real returns on bills and bonds do not necessarily reflect the *ex ante* expectations of investors. For example, a lagged growth in inflation expectations before the 1980s and a lagged decline in inflation expectations from the 1980s seem to have been key factors in marked shifts in observed annual rates of return on bills and bonds.

Consequently, as yields on nominal government bills and bonds are affected by inflation rate expectations, yields on inflation-adjusted bonds should provide a better insight into the RFR than yields on nominal bonds. However, inflation-adjusted bonds are a relatively new form of security which have been traded in some markets only since the 1980s.

Moreover, yields on inflation-adjusted bonds have progressively reduced over the last 20 years. Specifically, it appears that the real RFR has fallen markedly over this period. Current estimates of the RFR would therefore be very low or even negative. A cautious forward estimate of the RFR might therefore recognise that negative yields are unlikely to be sustained, particularly as yields can vary significantly over relatively short periods of time. In general, the spot rate is the best measure of the current expectation of the future RFR given it incorporates, in theory, all evidence available at this time. However, some regulators and practitioners do not believe current spot rates can safely be used for a CAPM assessment, given that current yields are affected by what are expected to be 'temporary' actions of the monetary authorities, such as quantitative easing and other unconventional monetary policies.

6.2.2 The market risk premium (MRP)

In principle, the RFR and MRP should be considered together as they are the two components of the expected return from a well-diversified investment portfolio, that is, the summation of the two gives the total market return. Regulators are generally interested in returns from international markets as investors considering investing in a gas network of a particular country will typically have the choice of investing in other assets either inside or outside of the relevant country.

Below we consider the approaches to estimating total market returns and consider the implications for the market risk premium.

Approach to estimating total market return (TMR)

There are a range of approaches by which TMR can be estimated. In broad terms, these approaches rely either on:

- Historical data, reflecting actual returns over time, or
- Forward looking data, reflecting investors' expectations of returns.

Whilst there is no consensus on the most appropriate approach to estimating market returns, many regulators have used historical data, often over prolonged periods. This was an approach advocated in the widely cited and influential 'Smithers & Co' report of 2003 commissioned by some of the UK's competition and regulatory authorities.[24]

A more recent report commissioned by the UK Regulators Network (UKRN) updated and extended the analysis of Smithers & Co.[25] The UKRN's report recommends "*that regulators should continue to base their estimate of the EMR* [Expected Market Return] *on long-run historic averages*".[26] Whilst recognising alternative methods, the authors were unable to identify a method "*that would be as straightforward to implement as the existing approach, nor … that would be robust to criticism.*"

Historical evidence on TMR

A standard reference for historical market returns is the Global Investment Returns Yearbook produced annually by leading academic authorities from the London Business School, Dimson, Marsh and Staunton (DMS), and currently sponsored by Credit Suisse. DMS have been assessing historical market returns and equity market premiums for some time and their dataset now contains 118 years of data, from 1900 to 2017.

Table 9 presents real returns to equity investors in the US, European and world markets as presented in DMS's 2018 yearbook.[27]

[24] A Study into Certain Aspects of the Cost of Capital for Regulated Utilities in the UK, 2003, by S. Wright, R. Mason and D. Miles, on behalf of Smithers & Co.
[25] Estimating the cost of capital for implementation of price controls by UK Regulators, 2018, by S. Wright, P. Burns, R. Mason and D. Pickford.
[26] Page 8, op cit.
[27] Credit Suisse Global Investment Returns Yearbook Summary Edition, 2018, by E. Dimson, P. Marsh and M Staunton.

Table 9 Annualised real equity returns in different markets and return periods

Return periods	US	Europe	World
2000-2017	3.5%	2.5%	2.9%
1968-2017	5.7%	6.3%	5.3%
1900-2017	6.5%	4.3%	5.2%

Source: Dimson, Marsh, and Staunton, cited in the Credit Suisse Yearbook.

Note 1: DMS's Europe grouping comprises 16 European countries, and its World grouping 23 countries.

Note 2: returns expressed as geometric mean returns.

These returns show wide variability, depending on the period chosen – with values ranging from a low of 2.5% (Europe, 2000-2017) to a high of 6.5% (US, 1990-2017). Perhaps most notably, for each market, the annualised returns calculated over the longest period (1900 – 2017) were higher than for the shortest period (2000-2017). This shows the importance of choosing the relevant time-period.

Relevant time-period

Consideration of the time-period for measuring TMR involves a trade-off between the strengths and weaknesses of long-term and short-term data. These trade-offs are presented in Table 10.

Table 10 Comparison of approaches for measuring the equity market risk premium

	Longer-term returns	Shorter-term returns
✓	Includes but reduces the impact of extreme events, eg 1929 Great Depression, 2008 Global Financial Crisis	Captures market information more akin to the current market, and more in line with short-term investor preferences
✘	Assumes markets (and TMR) are comparable over time, but which markets?[28]	May be overly influenced by a lot of noise/short term events, including financial crises and market corrections

Source: ECA

Arithmetic or geometric averages of returns

The returns presented in Table 9 were calculated based on a geometric mean. However, returns can also be calculated using an arithmetic mean. Returns calculated as an arithmetic mean tend to be higher, by around 1%-2%.[29] In identifying an appropriate estimate of TMR, therefore, one needs to consider whether to use an arithmetic or geometric average. Box 1 provides a definition of each, and the rationale for using the different measure.

[28] Evidence presented by Dimson, Marsh, and Staunton in 'Triumph of the Optimists' (December 2002) and the FTSE All-World Index Series highlights major shifts in the make-up of global and national equity markets. At the global level, the contribution of US and UK equity markets have changed from 15% and 25%, respectively, in 1899, to 53% and 6%, respectively, in 2016. In the UK, shares in rail companies made up close to 50% of all equity in 1900, and now do not feature on a market break-down.

[29] See Appendix E of UKRN (2018) report.

Box 1 Arithmetic v geometric averages

Equity returns are typically calculated in one of two ways: arithmetic or geometric.

Arithmetic returns assume no correlation between returns, which is what a perfectly efficient market would suggest. Without correlation, it is possible to average the returns for a range of periods. For example, if consecutive years have returns of 10%, 8%, 5%, 6%, and 4%, the arithmetic average will simply calculate an average of the five returns, which is 6.6%.

Geometric returns reflect an annual equivalent return from the ‘opening price’ to the ‘closing price’, without consideration of the movements in between. From our same series of returns, the geometric average is 6.3%. Rather than demonstrating convincing evidence of being perfectly efficient, markets show evidence of mean reversion (and correlation between returns), which would favour using a geometric average.

Source: ECA

The arguments for both approaches are generally considered to be valid (ie that markets exhibit both a degree of efficiency without correlation between annual returns, and a degree of mean reversion). Accordingly, some regulators consider it appropriate to consider the range of both geometric mean returns and arithmetic mean returns, while others err on the side of caution and apply the arithmetic mean (given the importance of not undermining investment incentives).

In Table 11 we present differences between DMS’s geometric and arithmetic mean real equity returns (these data were presented in the 2017 edition of DMS, rather than 2018, as per Table 9).

Table 11 Annualised real equity returns 1900-2016

	US	Europe	World
Arithmetic mean	8.4%	6.0%	6.5%
Geometric mean	6.4%	4.2%	5.1%
Difference	2%	1.8%	1.4%

Source: Dimson, Marsh, and Staunton, cited in the Credit Suisse Yearbook.
Note: DMS’s Europe grouping comprises 16 European countries, and its World grouping 23 countries.

The above shows a difference between the two approaches of 2 percentage points for the US and 1.4 percentage points for the World.

Implications for MRP

There are two opposing ways in which to consider the MRP, which is required to estimate the cost of equity:

- That the **TMR is constant** and MRP is inversely correlated with the RFR. In these circumstances, total market returns are estimated and then the RFR is deducted to infer an MRP (TMR emphasis).
- That the **MRP is constant** and so TMR is positively correlated with the RFR. In these circumstances, MRP is directly estimated (MRP emphasis).

As with so many other aspects of WACC estimation, there is no consensus among academics or regulatory practitioners on whether the TMR is more stable (and that MRP should be calculated on this basis) or whether the MRP is more constant over time. Observed regulatory practice, however, in most places seems to favour an MRP emphasis.

6.2.3 The beta estimate

The equity beta (β_E) is a measure of risk associated with a specific investment relative to the market (of all investable assets). Beta indicates how responsive an investment is to movements in the market as a whole. An equity beta of less than 1 means an investment is less risky than the market and a lower return is appropriate; an equity beta of greater than 1 means an investment is riskier than the market and a higher return is appropriate.

The equity beta of a listed firm is often measured as the covariance between the firm's share price and the equity market as a whole (as proxied by some benchmark index). However, many regulated companies are not listed, and their equity beta therefore cannot be directly estimated. It is for this reason that regulators will often set the beta for unlisted regulated companies based on the betas of comparable companies that are listed and/or from betas used in other regulatory determinations.

Equity betas and asset betas

In making this comparison, regulators typically adjust the equity beta to take account of different levels of gearing between the listed and unlisted firms. This is because higher gearing results in a higher equity beta. To adjust for differences in gearing, regulators use the equity beta and gearing of the listed company to calculate an 'asset' beta, which is a construct intended to measure beta assuming no debt (deleveraging). This asset beta is then leveraged using the gearing level of the unlisted firm. An asset beta cannot be observed, and therefore must be derived from observed equity betas.

The correct formula for leveraging and deleveraging betas is below. Typically, the tax term is omitted and, often, the debt beta is assumed to be zero (a reasonable assumption for investment grade debt, but less realistic otherwise).

$$\beta_E = \beta_A + (\beta_A - \beta_D) \times (1 - t) \times \frac{D}{E}$$

Where:

β =	Beta
A =	Asset
E =	Equity
D =	Debt
t =	Rate of corporate tax applicable to tax shelter on interest costs.

Evidence on beta

To provide some context to the betas typically used for regulated gas transmission companies, below we present some illustrative evidence on betas of international gas companies and of betas used by some regulators in setting a cost of capital for gas transmission companies. During the data collection phase of the assignment, we will be requesting data on the betas employed by the EU NRAs in their latest regulatory decisions and will be comparing these across member states.

International gas network companies – market derived estimates

In Table 12 we present the equity and asset betas of 11 listed companies with gas transmission activities. These companies all have activities other than gas transmission. These other activities include electricity transmission, gas storage, oil pipelines, etc. The average equity beta is 0.78 and the average asset beta 0.34.

Table 12 Equity and asset betas – market derived estimates

	Country	Equity beta	Gearing	Tax	Asset beta
Enbridge Inc.	Canada	0.65	52.9%	15%	0.33
TransCanada Corp.	Canada	0.66	63.5%	15%	0.27
Williams Companies Inc.	USA	1.39	68.4%	21%	0.51
ONEOK Inc.	USA	1.21	62.3%	21%	0.52
National Fuel Gas Co.	USA	0.89	52.8%	21%	0.47
Kinder Morgan Inc.	USA	0.59	53.0%	21%	0.31
Ren Redes Energeticas Nacionais SGPS SA(REN)	Portugal	0.75	66.1%	29.5%	0.30
Enagas SA	Spain	0.36	69.1%	25%	0.13
Snam SpA	Italy	0.28	67.1%	24%	0.11
National Grid PLC (NG)	UK	0.83	60.8%	19%	0.37
Transgaz SA	Romania	0.95	65.3%	16%	0.37
Average (mean)		**0.78**	**61.9%**		**0.34**

Source: Reuters (beta and gearing) and ECA analysis.
Note: Canadian tax rate based on federal corporate tax rate plus the mid-point of the range of provincial corporate tax rates.

In the above, we have relied on the equity betas derived and presented by Reuters. In practice, there are a range of options when estimating betas, including the measurement period and the frequency of data (eg daily, weekly, monthly). In Table 13 we present asset betas for four of the above companies (the European firms) using different measurement periods (2, 5 or 10 years) and different return periods (daily, weekly or monthly), along with the average beta across companies for each of these different options. Depending on the measurement approach, the average asset beta across the four companies is in the relatively narrow range of 0.30 to 0.36, with an overall average of 0.34.

Table 13 Asset betas – market derived estimates

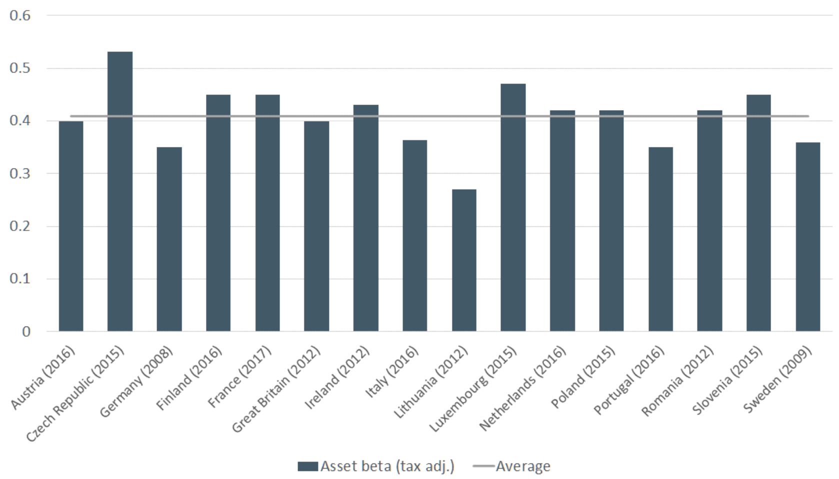
Measure	NG	Snam	Enagas	REN	Average
2-yr daily	0.33	0.36	0.29	0.29	**0.32**
2-yr weekly	0.40	0.27	0.31	0.29	**0.32**
5-yr daily	0.39	0.39	0.34	0.21	**0.33**
5-yr weekly	0.42	0.45	0.34	0.21	**0.36**
5-yr monthly	0.44	0.38	0.32	0.30	**0.36**
5-yr daily with world index	0.31	0.33	0.50	0.23	**0.34**
10-yr daily	0.38	0.28	0.38	N.A.	**0.35**
10-yr weekly	0.38	0.27	0.38	N.A.	**0.34**
10-yr monthly	0.28	0.21	0.42	N.A.	**0.30**
Overall average					**0.34**

Source: Appendix E, UKRN (2018). Note: REN started trading less than 10-years ago and, therefore, 10-year returns are not available.

Regulatory precedents for gas transmission companies

In addition to the above evidence of estimates for gas transmission companies, in Figure 30, we present the asset betas used by European energy regulators in setting the cost of capital for gas transmission companies.

Figure 30 Asset betas - regulatory precedents



Source: CEER Report on Investment Conditions in European Countries, December 2017

These regulatory precedents show gas transmission asset betas in the range 0.27 to 0.53, with an average of just under 0.41. This is a somewhat higher range and average than the more recent market derived estimates in Table 13 above. However, both sets of results confirm that regulated gas transmission companies are generally considered less risky than the stock market as a whole, largely because of the regulatory regimes that govern their revenues.

6.3 Country risk premium

It is frequent practice to include a country risk premium in the computation of the cost of equity. Practitioners typically estimate a country risk premium with reference to sovereign risk spreads for the relevant country. Some attach the premium to the risk-free rate (to establish the equivalent of a country-specific interpretation of the risk-free rate) while others attach it to the market risk premium (to establish the equivalent of a country-specific premium for equity investments). A commonly cited exponent of the country risk concept, Professor Aswath Damodaran (Stern School of Business, New York University), identifies the country risk premium as a separate component of the cost of equity and adopts a multiple of the sovereign risk spread, typically 1.5 times.

Although these adjustments are often framed in theoretical terms, there are critics who argue they are neither empirically nor theoretically supported[30] and that they are 'fudge factors' that should be avoided by making unbiased forecasts of a project's cash flows[31].

In the absence of much evidence for a systematic component of country risk[32], in CAPM terms, country risk will be strictly diversifiable for a global portfolio investor: the market should not expect higher returns overall. The market would, however, require higher returns to be built into forecasts to compensate for downside risk of adverse political and economic conditions in the country that are not otherwise factored into those forecasts. This presumably provides the theoretical foundation for continuing to use country risk premiums in some countries.

6.4 Cost of debt

The cost of debt is the interest payable to lenders. In a regulatory context, the first basic decision to be made is:

- whether to pass-through actual interest costs, or
- to separately calculate an interest cost and set an *ex ante* WACC with the regulated company then keeping or incurring the difference between the allowance and its actual interest costs (as an incentive for it to borrow/re-finance efficiently).

In other words, where an *ex ante* interest cost is determined, this is then combined with the allowed cost of equity to obtain an estimated WACC which, when multiplied by the RAB, gives the overall allowed return. The utility is then responsible for meeting interest payments out of this return.

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30 Lutz Kruschwitz, Andreas Löfflery & Gerwald Mandlz, 'Damodaran's Country Risk Premium: A Serious Critique', July 2010, Available at SSRN: http://ssrn.com/abstract=1651466.

31 Richard Brealey and Stewart Myers (with the Brattle Group), 'Capital Investment and Valuation', 2003, McGraw-Hill.

32 Campbell R. Harvey, 'Country Risk Components, the Cost of Capital, and Returns in Emerging Markets', Available at SSRN: http://ssrn.com/abstract=620710 or http://dx.doi.org/10.2139/ssrn.620710.

If the decision is taken to estimate an *ex ante* cost of debt, then a further basic design decision is needed on whether this should be a current or 'spot' estimate or whether it should reflect the historical (or 'embedded') interest costs of debt, calculated with reference to market indices or other indicators (and whether these are specific to the regulated company or look broader at comparator businesses). Hence, in broad terms, there are two main ways of estimating the cost of debt:

- Using a company's **actual (ie embedded) debt costs**. A company's historical cost of debt can usually be observed directly from their financial accounts (note the difference to passing-through debt costs is that there is no subsequent true-up for actually incurred costs).

- Using **market-based estimates**. This can be done through adding a debt premium (based on the company's credit rating) to a risk-free rate (this may be the same or different to the risk-free rate used for estimating the cost of equity, although the latter RFR should act as a minimum value) or by using an index of corporate bonds[33] (again, with the same or similar credit ratings), if one exists.

In practice, these approaches need not be mutually exclusive. For example, a company's expected costs of existing debt could be used as the return on embedded debt, whilst the return on expected new debt could be set using a market-based estimate.

The choice between the alternative approaches, as with other aspects of the revenue setting framework, comes down to the desired trade-off between economic efficiency and guaranteeing cost recovery. The use of a spot estimate of the current interest cost (and notional gearing – see below) is (theoretically) the most efficient approach—it reflects the current cost of funding the next or marginal project by an efficiently financed firm and, therefore, should move regulated prices towards marginal cost. It provides an incentive for the regulated firm to try and find lower-cost sources of financing than the market average. And, by using external benchmarks, it means that a network business is not rewarded if it borrows at interest rates above the market level and/or correspondingly uses an inefficient capital mix.

The main disadvantages of using spot estimates and notional gearing rates are that these can be difficult to calculate with any degree of certainty (for example, spot rates might be influenced by specific, non-representative events ie they may contain 'noise') and based on meaningful comparators for the regulated utility. This means a substantial risk that actual and allowed costs of new debt are very different, and that current interest rates may be very different to historical levels. This can lead to the regulated businesses making large windfall gains or losses where current interest rates are above or below those of historical loans respectively. This was an issue in Great Britain, for example, and is why, as mentioned above, the regulator recently moved from spot estimates to the use of a 10-year rolling average of a widely-used corporate bond index to better align the actual and allowed costs of debt in the revenue control.

The use of an average historical cost of debt based on a market index represents an intermediate position between spot estimates and actual embedded interest costs. It should better reflect the actual costs of debt of the regulated business and, therefore, avoid large

[33] This is the approach adopted by the GB energy regulator Ofgem for gas transmission (and other networks). Ofgem uses the iBoxx non-financials index for A and BBB credit ratings.

gains or losses for the business. But, at the same time, it should still provide an incentive for the regulated business to try and lower its borrowing costs below the market average.

6.5 Gearing

There are two main options for setting gearing in the WACC:

- **Actual gearing** – under this option, the actual capital structure of the company as it currently stands or is expected to stand over the regulatory period is used
- **Notional gearing** – under this approach a notional level of gearing is used, based on what may be considered a typical, objective or efficient capital structure without regard to the actual capitalisation of the company under review.

Notional gearing tends to be preferred by regulators. However, the difference between these two approaches is not so great if the interaction between gearing and the equity beta is considered. There is a common, but simplistic, analysis that as debt is cheaper than equity, higher gearing will reduce the WACC. However, this overlooks the interaction between gearing and the equity beta described in section 6.2.3. If a company increases its gearing (the share of its capital represented by debt), the business risk will be more concentrated on a smaller value of equity, and shareholders will therefore require higher rates of return (the equity beta will increase). This will offset (to some extent) the greater weight placed on debt.

6.6 Fineanceability

Where utilities are undertaking major capital expenditure programmes, it may well be that allowed revenues are insufficient to generate the cash required to fund investments. This is more likely under a RAB-based methodology for establishing capital costs but can also happen under a cash-based methodology where the return on equity is set low and the utility cannot borrow to cover the full costs of its investment programme.

The concept of a financeability test is to assess whether a proposed set of allowed revenues are adequate for a utility to meet a set of financial criteria and, if not, to make upward adjustments to these allowed revenues to enable it to do so. The obvious disadvantage of a financeability test is that it may imply very large increases in allowed revenues and tariffs from one year to the next, even if these are not necessarily permanent.

Where a financeability test is applied, adjusting the return on equity is probably not the optimal mechanism to bring allowed revenues and cashflow needs into alignment. It may prove difficult to reduce the return on equity in future, once the need has passed, because the owners, management and employees of the utility will have come to expect a much higher return and level of profits. Large increases in the return on equity will also attract strong opposition from stakeholders[34]. However, alternatives can be used. An obvious one is

[34] Increasing the return on equity can additionally lead to a permanent increase in allowed revenues even after the need for it has disappeared. The higher profits generated by the increased return are added to the equity of the utility and, therefore, increase future allowed returns (as these are calculated as return on equity multiplied by the value of equity).

equity injections, replacing the need for debt financing. Alternatives that do not require equity injections include adjusting depreciation profiles to increase current depreciation allowances and reduce future ones, and temporary financing adjustments, which are subsequently recovered through reductions in future allowed revenues. Both mechanisms bring cash forward from future years but do not mean a permanent increase in revenues and charges. They do, however, lead to current users paying for assets that benefit future users.

7 Other regulatory mechanisms

The revenue setting methodologies discussed in Section 3.1, and especially the Building Blocks methodology, are employed to set a baseline revenue requirement on an *ex ante* basis for a given regulatory period. However, there may be a need to adjust revenues either to account for outturn costs and activities (ie on an *ex post* basis) or to modify the profile of revenues to smooth out any large fluctuations in underlying costs. Any such mechanisms are sometimes specified by regulators on an *ex ante* basis, so that they inform future decisions by the utilities and do not retrospectively alter the impact on the regulated firms of their past decisions.

For the purposes of the present review, we set out the key issues in relation to the following mechanisms commonly used in some regimes:

- **Efficiency sharing mechanisms** ie adjustments to revenues deriving from savings in operating and capital expenditures (compared to projections used for setting the revenue requirement), but applied in a way that incentivises utilities to pursue such efficiencies while simultaneously ensuring that the benefits are shared with users
- Those that **reflect the uncertain nature of costs** and therefore reduce the risks of the utilities for those matters that are largely or entirely outside their control, including straight cost pass-through mechanisms
- **Incentive payments and penalties** that increase/decrease the realised revenues (and therefore profits) of the utilities consistent with a transparent performance regime that sets clear quality and performance targets
- **Smoothing mechanisms** that moderate changes in revenues and the impact on network users and customers.

Finally, as it is impossible to foresee and account for all conceivable eventualities, in some limited and exceptional circumstances regulators may allow for the re-opening of the revenue determination. We discuss this matter at the end of this Section.

7.1 Treatment of underspends and overspends

7.1.1 Capital expenditure savings or overruns

No sharing within the regulatory period

Capital expenditure affects utilities' revenues through the return on capital and depreciation components of allowed revenues. Some price/revenue cap regimes incentivise efficient capital expenditure by setting allowed revenues using forecast expenditure and not making any adjustments for the difference between forecast and actual until the end of the regulatory period. **At the end of the regulatory period the RAB is updated based on actual capital expenditure** undertaken during the period and actual or forecast depreciation, but there is no reconciliation for the over/under-recovery of allowed revenues due to capex under/over spends. This means that:

- If the utility 'beats' the capital expenditure allowance underpinning the return on capital calculation used for setting allowed revenues, then it keeps the difference (the return on the expenditure not undertaken) until the next regulatory period (and correspondingly, incurs the cost of any cost overruns).

- From the next regulatory period onwards, revenues are set based on the actual capital expenditure incurred, and therefore consumers would reap the benefit of more efficient capital expenditure (or pay for the additional investments made).

Efficiency benefit sharing mechanism

The key weakness of the above approach to incentivising efficient capital expenditure is that it discourages savings late in the regulatory period, because the utility will keep the benefit for a shorter period. Utilities therefore have an incentive to delay expenditure until the beginning of the next regulatory period and retain the benefit for longer.

A capital expenditure sharing mechanism is therefore sometimes used to achieve constant incentives in each year of the period. A sharing mechanism generally operates as follows (although there are several variants to this):

- At the regulatory review, the over/under spend on capex is calculated for the recently completed regulatory period

- The value of the cumulative over/under spend is calculated

- A certain sharing ratio is applied to this amount

  - The ratio applied to under/ over-spending can be asymmetric, to further protect against users or consumers from the risk of the utility over-spending

- The above calculations then result in an adjustment to allowed revenues for the forthcoming regulatory period.

Rolling incentives

The above is not the only mechanism that might be employed. An equivalent or similar outcome is sometimes achieved through 'rolling incentive mechanisms', which allow the utility to retain the benefits of an efficiency improvement for a period of time (say, five years), after which the improvement is incorporated into the revenue requirement calculations. For example, if an efficiency gain is made in year three of a five-year regulatory period, the revenue requirement would not adjust to incorporate this until year three of the next control period.

Application of sharing or rolling incentive schemes

While capital expenditure sharing mechanisms can ensure that the incentives on utilities are constant in each year of the regulatory period, they add more complexity. Hence, most regulators usually adopt a simple incentive-based regime initially (ie with no clawing back of savings or sharing of overspends during the regulatory period) and consider more complex sharing mechanisms in future when greater experience and confidence of the incentive-based regime is gained. We note also that such sharing arrangements are only relevant where investments are added to the RAB 'as spent', rather than upon commissioning of the relevant assets.

Ex post reviews and deferrals

Another regulatory tool that regulators employ is the conduct of *ex post* reviews of capital expenditure. If certain criteria are met, the disallowed portion of the capital expenditure is excluded from the RAB. The criteria against which capital expenditure is disallowed on an *ex post* basis typically includes the following:

- Capital expenditure incurred that was above the allowance and is deemed to be inefficient or imprudent (for example, was not part of the approved network development plan or was realised at a much higher cost than planned)
- Capital expenditure incurred due to inflated 'related party' margins
- Capitalised operating expenditure resulting from a change in capitalisation policy that had already been recovered through allowances for operating expenditure.

Some regimes also allow the regulator to make ***ex post* adjustments for capital expenditure that was deferred without adequate justification**. This is because utilities should be rewarded for reducing construction costs, for example, or identifying alternative less expensive projects that achieve similar outcomes, but not for simply deferring capex to spend less than the regulatory allowance or for expenditure delayed by factors outside the utility's control. In practice, however, it is often difficult to differentiate 'true' savings from other deferrals.

7.1.2 Operating expenditure savings or overruns

Operating expenditure incentive mechanisms

As with capital expenditure, one way to incentivise efficient opex is to:

- Set allowed revenues using forecast operating expenditure and make no adjustments for the difference between forecast and actual expenditure, but
- When allowed revenues are set for the next regulatory period, the starting point would reflect historical operating expenditure (and therefore usually be lower if savings were made in the last regulatory period) which would benefit users or consumers (the 'ratchet effect').

Alternatively, an operating expenditure sharing mechanism could be adopted that would work much the same as a capital expenditure sharing mechanism – allowed revenues would be adjusted at regulatory reviews to ensure that the benefit/cost of opex under/over-spends are always kept (for a fixed period of time) based on a sharing factor, regardless of when they occur. Another possibility would be allowing the utilities to retain the benefits of an efficiency improvement for a set period, after which the improvement is incorporated into the base revenue requirement calculations (rolling mechanism).

Difference between incentive mechanisms for capital and operating expenditures

Sharing mechanisms for operating and capital expenditures have slightly different implications due to the way they are incorporated into allowed revenues (directly for opex, indirectly for capital expenditure through depreciation and return on capital over time). The use of sharing mechanisms for capital expenditures is primarily about ensuring constant incentives throughout the regulatory period. Even in the absence of a sharing mechanism, capital expenditure under/over-spends are shared between utilities and users through lower/higher future depreciation (if actual rather than forecast depreciation is used in the asset base roll-forward equation) and return on capital. Depending on the return on capital, the asset life and when the under/over-spend occurs, utilities receive approximately 10 to 30 per cent of the benefit/cost, with users receiving the rest.

Opex is different. If utilities under-spend on opex, they keep the full benefit in that year and users do not share any direct benefit (only indirect benefits in the form of lower opex allowances in the next regulatory period). It is for this reason that some regulators apply an opex sharing mechanism, ie to guarantee that opex savings are directly shared between utilities and consumers.

7.2 Pass-through and uncertainty mechanisms

The rules for adjusting allowed revenues often allow changes in the costs of certain inputs to be passed through to users. These cost pass-throughs allocate the risks of the cost of these inputs to users. Cost pass-throughs generally only comprise a share of operating expenditure that is deemed to be uncertain, significant, and outside of the control of the utilities.

The general principle employed for treating elements of operating and/or capital expenditure as pass-through is if they can be shown to be substantially outside the influence of the utilities and are significant enough to have a material distorting impact on the utilities' ability to finance their activities.

Also, depending on the nature of such costs, some are treated differently to straight pass-throughs and regulators instead employ other 'uncertainty mechanisms'. Such uncertainty mechanisms may include:

- **Output-driven adjustments** where the revenue requirement is set based on a unit price or allowance for an operating or capital expenditure item multiplied by a forecast driver for that item (for example, the metres of pipeline). Any difference in outputs (for example, additional pipeline) between that used for setting the revenue requirement and the outturn would result in an adjustment in the next regulatory period (ie the adjustment would be calculated as the allowed unit rate multiplied by the actual driver output less the allowed unit rate multiplied by the forecast driver output).

- Recognition, in setting the revenue requirement, of a category of cost, the magnitude or timing of which might be uncertain (eg because it depends on or is impacted by impending changes to government laws or regulations) and therefore there is an ***ex post* adjustment** in the subsequent regulatory period for efficient costs incurred. This is like, but distinct from, pass-through costs in that the adjustment is not automatic, but subject to an *ex post* efficiency or prudency review.

- **Contingent projects** - if it is unclear whether a project will be needed during the forthcoming regulatory period due to difficulty in forecasting demand or other parameters, a project may be included in the revenue requirement as a 'contingent project' with the utility being able to recover the costs of the project only if a pre-specified trigger event occurs.

We note that any such uncertainty mechanisms are generally separate from any other arrangements that encourage utilities to contain their costs (ie through efficiency benefit sharing incentives discussed above) or to fully protect the utilities against cost items deemed to be completely outside their control (pass-through costs).

7.3 Incentive payments and penalties for quality performance

Some regulatory regimes have incentives for utilities to maintain or improve service quality levels as well as to reduce costs. This is done to ensure (especially with price/revenue cap regimes) that improvements in cost efficiency are not at the expense of quality of service.

The regulation of quality in the gas transmission sector is multi-faceted and many operational aspects will already be regulated through minimum standards and regulations (eg for safety). However, beyond such standards, some regulatory frameworks contain **a** performance regime for utilities, which is generally limited to a small number of factors that concentrate attention on those aspects that are likely to be important to users (and for which there is reliable and useful data).

Once key performance indicators are established, rewards and penalties are developed for their achievement or failure. These rewards and penalties are then applied as adjustments to the allowed revenues. This approach has several benefits in that it:

- Can be used to target various aspects of quality of service (that may be valued by users)

- Provides strong incentives for achievement (if the payments are set at the right level), as the rewards/penalties directly impact utilities' profitability

- Ensures a sufficient degree of certainty to utilities of the consequences of being within the targeted quality range.

The main drawback is that users might consider they are paying twice (through the allowed expenditures and revenues, and the performance regime) for the service to which they are in any case entitled.

7.4 Revenue smoothing

Smoothing of revenues within a regulatory period are sometimes used to moderate the effect of large investments (occurring part way through a regulatory period) on users by effectively averaging out forecast costs. In practical terms, this is a mechanical calculation undertaken at regulatory reviews and can be simplified as follows:

- ❑ The costs of the service providers are forecast for each year of the regulatory period
- ❑ Allowed revenues, which are constant in each year of the regulatory period, are determined such that the present value of forecast costs is equal to the present value of allowed revenues over the regulatory period.

If significant changes in volume are expected over the period, revenues can be smoothed such that the average tariff is equal in each year. Technically, this is done by dividing the present value of forecast costs by the present value of forecast volumes.

Whenever revenues are smoothed, the cashflow impacts on utilities are also generally considered. Smoothed revenues mean that utilities' annual revenues may be substantially different to their annual costs, which could cause difficulties for financing large investments. Hence, regulators generally wish (or have the obligation) to ensure any smoothing does not jeopardise the ability of utilities efficiently financing their activities.

7.5 Re-opening the revenue determination

Even with a carefully designed regulatory regime and the development of more detailed rules regarding the various revenue adjustment mechanisms discussed above (and other aspects of the framework), circumstances can change in ways that cause the utility to suffer very large financial losses or make significant profits. Under such circumstances there is sometimes the possibility for either a utility or the regulator to initiate a re-opening of the revenue determination (ie prior to the normal periodic review) to deal with the specific extraordinary circumstances.

Any such re-opening is generally limited to situations where a major unforeseen event occurs that is outside the control of the utility and which has a significant monetary impact (positive or negative) on the regulated firm. The need for any such re-openings is generally assessed on a case-by-case basis, but regulators sometimes employ certain materiality thresholds for the financial impacts to provide greater transparency and certainty to both users and the utility about the bounds of any such re-openings.

8 Conceptual framework

8.1 Introduction

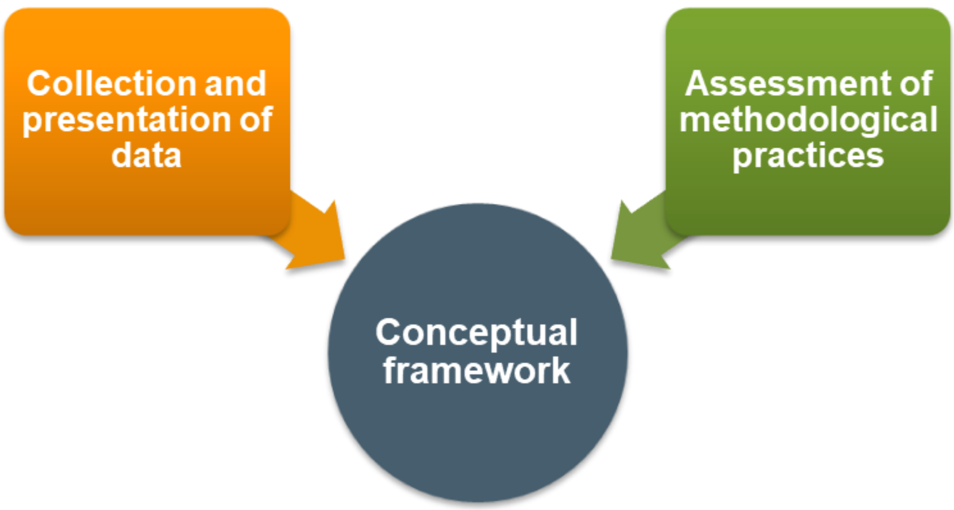
The study ToR required us to develop a conceptual framework to guide the documentation and comparative analysis of the methodological approaches adopted by the NRAs. This was needed to ensure that the information is collected and presented in a systematic and structured manner to facilitate understanding and comparisons, and thereby permit the drawing of meaningful inferences or conclusions.

We interpreted this task as requiring two distinct considerations:

- **How best to assemble, present and compare the data?**
- **How to assess the resulting information and described approaches?**

These elements of the framework are illustrated in Figure 31 below and are discussed further in the sub-Sections that follow.

Figure 31 Components of the conceptual framework

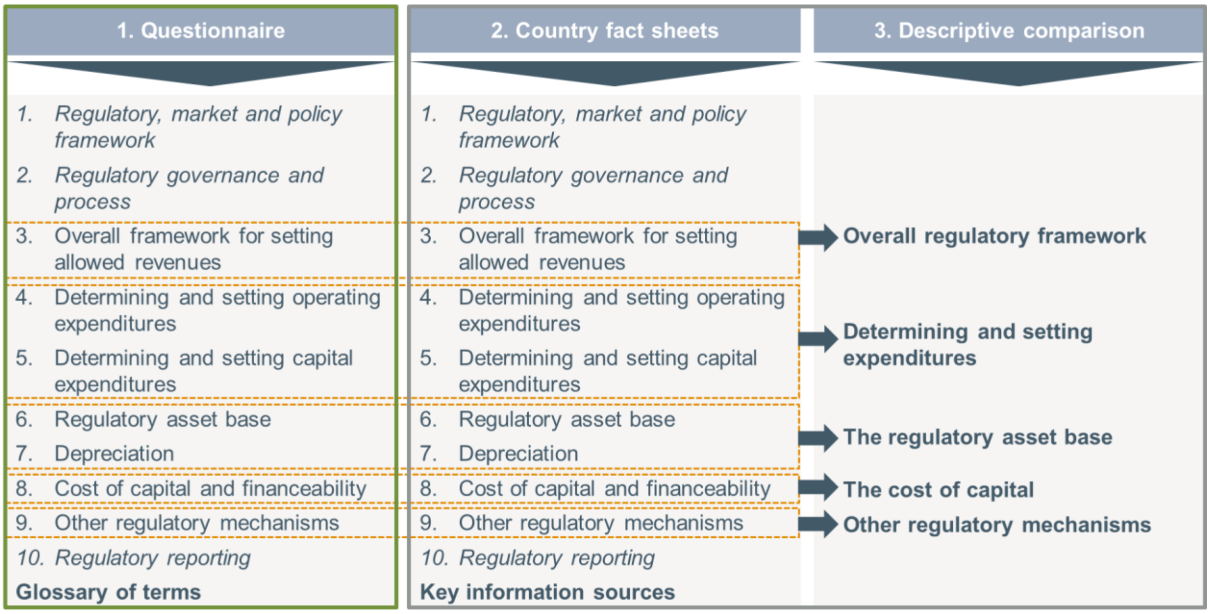


Source: ECA (based on interpretation of the study ToR)

8.2 Collecting the data and comparing regulatory practices

The overall approach to collecting and presenting the relevant information regarding the revenue setting methodologies employed in the various EU jurisdictions is summarised in Figure 32 below.

Figure 32 Scope and presentation of information on the regulatory frameworks employed



Source: ECA

As shown in the figure, the three key parts of the approach comprise the following:

1. **A questionnaire issued to the 27 NRAs** (see Annex 17), which was the basic tool for assembling the required information (and is therefore differentiated in the figure above by a green border) – as discussed in Section 2.1, the questionnaire design drew on the literature survey, the Code requirements and our knowledge and experience to define the key methodological matters to be considered and the scope of the survey. To facilitate responses from the NRAs, the questionnaire contained pre-selected answers (wherever possible) together with corresponding short explanations to clarify questions. There was also room for written comments, if NRAs wished to provide additional explanations or felt that the structured answers did not satisfactorily reflect their circumstances. As shown in Figure 32, the questions were structured around 10 topic areas:

    - Sections 1 and 2 of the questionnaire serve as background and they cover some basic parameters that characterise the sector in the respective countries[35], together with the *process* governing the setting of revenues and tariffs (this was used primarily to provide context for the discussions that followed with the NRAs and to explore the degree to which sector characteristics might shape the approach adopted in each country – as matters transpired, and to our surprise, in most cases we did not identify any explicit nexus between country circumstances and the regulatory approach used[36])

    - Sections 3 to 9 variously explored the different elements of the revenue setting framework, starting from the overall approach, through to the

[35] As some of this information is TSO-specific, an annex was also prepared to allow those countries with multiple TSOs to submit the requisite information at the individual TSO level.
[36] This is not to say that such a connection is not present, but it did not seem to be at the forefront of NRA considerations.

various elements of the cost 'building blocks' (operating expenditure, capital expenditure, asset base and depreciation, and cost of capital) and the use of other mechanisms primarily for managing volume risk and/or providing incentives – these topic matters closely follow the discussion of the previous sections of this Part I

- Section 10 covered the issue of regulatory reporting, which we consider to be particularly important given that its absence can undermine the effectiveness of any regulatory framework (irrespective of the methodology used for setting and controlling tariffs) – regulators generally need information to develop a view about the reasonableness of TSO costs and help address the inherent information asymmetry between the regulatory authority and the regulated business

- The questionnaire also contained a glossary of terms to aid understanding of the questions posed and to possibly form a basis for the standardisation of terminology used.

2. **Country fact sheets** in tabular format for each of the countries or 27 NRA jurisdictions – these are structured summaries of the main principles and arrangements governing revenue setting, and together with the more detailed responses of the questionnaires form the 'database' of information for describing and comparing (in the next step below) the various regulatory practices. As shown in Figure 32 above, the sections of the fact sheet correspond to the same sections in the questionnaire, although to keep the presentation simple (thereby ensuring that the sheets could act as effective 'quick reference' guides), only summarised information for a subset of the questions asked is presented; the aim, however, was that this data satisfactorily capture the essence of the arrangements and contain the information required by the Gas Tariff Network Code. At the bottom of the fact sheet, we also provide links (wherever these were provided) to the NRA site and the revenue setting methodology (where it is published), plus (in some cases) other relevant publications.

   The template adopted for the country fact sheets (including how this maps onto the questionnaire) is contained in Annex A5. The subsequently completed country fact sheets are included in Section 16 of the Report. The sheets have been grouped around broad categorisations of the overall approach used to setting or controlling revenues, namely:

   - Revenue cap regimes (Section 16.1)
   - Price cap regimes (Section 16.2)
   - Cost plus / rate of return regimes (Section 16.3)
   - Hybrid regimes (Section 16.4)
   - 'Other' regimes ie those that cannot be classified under the above (Section 16.5).

3. **Descriptive comparison** – this forms the greater part of Part II of this Report and attempts to distil the information generated in the previous two steps further, to

highlight the commonalities and differences in the approaches employed by the NRAs. As shown in Figure 32, this reverts to focusing on the 'core' elements of the revenue setting framework (largely in the form explored in this Part of the Report, and the literature and regulatory practice overview) and is accompanied by descriptive text with key summary statistics and graphs/maps/tables (as required) to facilitate the comparisons. The key 'indicators' used to describe and compare the EU methodologies is set out in Table 14 below.

Table 14 Comparison of regulatory practices – key indicators and summary data

Topic area	Indicators (in graphical, tabular or map form)
1. Overall regulatory framework	▪ Type of regulation (revenue cap/price cap/etc) ▪ Approach to assembling the cost base (building blocks/TOTEX/etc) ▪ Duration of regulatory period ▪ Length of revenue-setting process
2. Determining and setting expenditures	▪ Cost assessment methods (bottom-up, top down, TOTEX, etc) for both opex and capital expenditure ▪ Use of cost pass-throughs ▪ Efficiency factors (whether used and, if so, factors applied)
3. The regulatory asset base (RAB)	▪ Methodologies for establishing starting asset values ▪ Methods of RAB valuation / updating ▪ Timing of when assets enter the RAB ▪ Use of *ex post* reviews of capital expenditure ▪ RAB composition (especially linepack, customer connection assets and working capital) ▪ Depreciation methodology and asset lives
4. The cost of capital	▪ WACC basis (pre-tax, post-tax or vanilla, real or nominal) ▪ WACC values ▪ WACC premiums ▪ Allowed or target cost of equity and underlying parameters (RFR, MRP, beta) ▪ Allowed or target cost of debt – methodology and debt premiums (where relevant) ▪ Gearing approach (actual vs notional) and levels
5. Other regulatory mechanisms	▪ Over or under-recoveries of revenue ▪ Treatment of underspends and overspends ▪ Performance metrics and rewards/penalties

Source: ECA

8.3 Assessing the methodological approaches

The first part of the conceptual framework is limited to a factual description of the approaches adopted by the various NRAs. The second part envisages an evaluation of the relative ***effectiveness*** of the various regimes.

In seeking to address this issue, we tried, as part of the literature review, to identify papers that have attempted to evaluate the performance of different regulatory approaches, which could therefore inform the evaluation framework for this study. We found that, while the theoretical literature and discussion of principles is extensive (in the spirit of the discussion already presented and covered in Sections 3 to 7 of this Report), there is relatively **little guidance on how to practically examine the effects of regulation** and the various incentive mechanisms, and **even less empirical research on the actual performance** of differential regulatory regimes and mechanisms in the gas (or energy) sector. This is not too surprising as such comparative institutional analysis is inherently difficult, not least because it is very challenging to disentangle the various factors that could impact on outcomes, such as:

- Historical circumstances in the various countries eg the form of ownership, legacy obligations and exploited (or unexploited) efficiency opportunities
- Geography and sector characteristics, such as gas sources and storage options, consumption patterns and the degree of interconnectivity
- The macroeconomic framework and business cycle, which affect among other things interest rates and input costs
- Growth in demand – this could be slow, fast or negative depending on economic circumstances, the maturity of the sector, the structure of downstream sectors (including electricity markets) and the composition of network users
- Differential standards regarding quality (firm versus interruptible supply) and security of supply
- Social and economic objectives regarding, for example, affordability and price stability
- National legal or other constraints such as the choice of funding models and target returns on equity, for example, for state owned companies.

Notwithstanding the above and the possible merits of exploring empirical outcomes under various regulatory regimes and incentive mechanisms, we believe that such an assessment is beyond the scope of the present study. We have therefore necessarily limited ourselves to a **qualitative assessment** of the regulatory frameworks and the five aspects that are listed in the left-hand column of Table 14 (and which are presented in Sections 10 to 14 of Part II of the Report).

This still leaves open the question of how the assessment of these five elements of the regulatory framework should be undertaken. This can only be done **by reference to the underlying objectives of the regulation of gas TSOs and therefore possible criteria that derive from these objectives**, as discussed further below.

8.3.1 What regulatory objectives might be relevant?

It is impossible to consider the effects of the regulatory approaches without reference to the objectives that govern the regulatory regimes. In this context, we note that the main relevant EU instruments – EC Directive 2009/73 concerning common rules for the internal market in natural gas, EC Regulation 715/2009 on conditions for access to the natural gas transmission networks, and the Gas Tariff Network Code - contain a long-list of objectives including (not in any particular order) the promotion and/or establishment of:

- Market integration *(Gas Network Tariff Code, Recital 1)*

- Security of supply *(Gas Network Tariff Code, Recital 1)*
- Interconnected gas networks *(Gas Network Tariff Code, Recital 1)*
- Consumer choice *(Directive 2009/73, Recital 1)*
- Cross-border trade *(Directive 2009/73, Recital 1)*
- Competitive and market prices *(Directive 2009/73, Recitals (1), (48) and (58))*
- Sustainability *(Directive 2009/73, Recital1)*
- Enhanced (wholesale) gas market competition (*Directive 2009/73, Recitals (16), (17), (33), (35), (47), (54) and (59))*
- Investment in infrastructure (*Directive 2009/73, Recitals (8), (9), (16) and (35))*
- Non-discrimination *(Gas Network Tariff Code, Recital (4) and Article 7(c), and Regulation 715/2009, Recitals (7), (11), (20), (28))*
- Transparency *(Gas Network Tariff Code, Recitals (2) and (3), and Regulation 715/2009, Recitals (7), (8), (15), (18) and (28))*
- Sufficiently compatible network services *(Regulation 715/2009, Recitals (10), (16))*.

Moreover, other regulatory objectives typically embodied in legislation across the EU (and elsewhere) include:

- Establishing cost-reflective prices
- Ensuring the financial viability of the regulated company/ies
- Providing incentives for cost minimisation and/or quality improvement
- Facilitating efficient investment
- Ensuring the regulatory regime is predictable, simple (or not unnecessarily complex) and transparent
- Minimising the costs for the regulator and the regulated firm(s).

While the objectives above form a useful frame of reference and are indisputably important in themselves, these cannot be readily adopted in a coherent assessment framework. Hence, for the purposes of the current study, we categorise the objectives into a broader and more encompassing grouping.

8.3.2 Assessment criteria

The grouping we propose recognises that there are some links, similarities and overlaps between the various objectives listed above thereby allowing them to be integrated. Collapsing the various objectives or criteria into broader categories also facilitates a clearer discussion and assessment of the potential impacts of the different regulatory approaches and practices.

The criteria we focus on are grouped under the following headings:

- **Economic efficiency** – it is probably uncontroversial to state that the overarching objective of the regulatory framework is to promote the goal of economic efficiency. We employ this term to encompass all dimensions of efficiency typically considered by economists – productive, allocative and dynamic (see Table 15 for further discussion of how these concepts apply in the present context) – and therefore it covers the efficient **operation** of and **investment** in the gas transmission system, both **now** and into the **future**. The promotion of economic efficiency is also closely linked with many of the objectives of EU legislation mentioned above (including of the Gas Network Tariff Code), for example:

  - ***Market integration*** – this is important, among other things, to the extent that it minimises the cost of investing in, operating and using the gas network (productive and allocative efficiency)

  - ***Security of supply*** – this requires the matching of supply and demand and therefore needs to be underpinned by efficient investment (productive and dynamic efficiency)

  - ***Interconnected networks*** – similar to market integration, this is significant because it may minimise overall investment and operating costs (productive efficiency).

- **Risk allocation** – revenues and tariffs are invariably set in advance, so realised outcomes will inevitably deviate from forecasts. A key element of the regulatory framework therefore is how the risk of realised outcomes differing from those forecast are allocated and managed (between the regulated company and network users and perhaps third parties). While there are different classes of risk that could be examined, our focus here is on:

  - ***Volume risk*** ie that outturn volumes or capacity will differ from forecasted volumes/capacity, and

  - ***Cost risk*** ie where actual costs are different to those that were forecasted or allowed[37].

- **Other regulatory and consumer issues** – under this heading we group several other criteria that are important from a practical implementation perspective, such as transparency, simplicity, predictability and reduction of regulatory costs (including those associated with regulatory 'gaming').

In employing the above criteria for assessing the differing approaches, we also examine the degree to which it might be desirable to strive for greater consistency between jurisdictions

[37] Another commonly cited risk is regulatory risk, but this can take different forms and is difficult to define. It is usually associated with the discretion allowed or exercised by regulatory authorities without applying clear and/or pre-established rules.

(or, conversely, whether there is merit in retaining differential approaches in an integrated market context).

Table 15 Application of efficiency concepts to setting allowed revenues

Efficiency dimension	Meaning	Application to revenue setting
Productive efficiency	Operation at least cost achieved when producing with the optimal combination of inputs (the latter is also termed technical efficiency)	TSOs incentivised to seek the lowest cost operation and investment, including least cost financing (subject to any constraints, such as risk)
Allocative efficiency	Prices based on opportunity costs so that a community generates the greatest return from its scarce resources	Mostly applies to tariff structures promoting efficient use, but in a revenue context also requires that costs be commensurate with those in a competitive market eg setting the cost of capital consistent with the expected return for an investment of similar degree of risk
Dynamic efficiency	Maximising productive and allocative efficiency over time	Mostly applies to having appropriate (and non-distorting) investment incentives, and incentives for improving economic efficiency over time including by finding better ways of producing the transmission services at the desirable level of reliability and quality

Source: ECA

Finally, we wish to clarify the reasons for excluding the following criteria, which on first viewing might appear to be conspicuously absent:

- **Financial viability of the regulated TSOs** (or the flip-side of this which is full cost recovery) – we take the safeguarding of the financial viability of the regulated TSOs as a given, which in any case is a commitment under EU and national legislative frameworks. Hence, while there might be differing views or approaches to setting the cost-recovery level (such as the reasonable rate of return), the elements of the framework are always assessed against achieving the 'revenue constraint' associated with the full recovery of (efficient) costs. Any desirable deviations from this revenue constraint are covered under the efficiency and incentives discussion, and the risk allocation criterion.

- **Promotion of competition and the efficient pricing of transmission services** – clearly, a major EU objective for the sector is to promote competition in the wholesale gas market, as explicitly stated in the objectives listed earlier and implied by other objectives such as promoting customer choice and cross-border trade, and achieving competitive prices. In this regard, the structuring of transmission system tariffs (which is outside the scope of this study) is more relevant rather than the underlying revenue constraint or revenue control mechanism. Generally speaking, decisions on the form of revenue control can be separated from decisions on the structure of tariffs. The exception is the relationship between the revenue control approach and the level of revenue risk for the TSO, but this is already covered under the risk allocation criterion.

Part II: Description and assessment of EU Member State methodologies

9 Introduction to Part II

9.1 Purpose and approach

The purpose of this second part of the Report is to document the current approaches adopted in the EU for setting the allowed or target revenues of gas transmission companies. The review covers 26 EU Member States (Cyprus and Malta are not included as they currently have no developed gas sector), but 27 NRAs (given that there are two regulators in the UK, one for Great Britain and another for Northern Ireland). As discussed in Part I, this comparison has been guided by the Code requirements and the issues that were identified in the literature and regulatory practice review as being particularly pertinent, and which were then embodied in the questionnaire issued to NRAs.

The questionnaire was the key instrument employed for collecting the information on which this part of the Report is based. Specifically, the approach used to collect and present the information has been as follows:

- **NRAs submitted their completed questionnaires** – most of these were returned broadly within the requested time (in March 2018), although some did delay until April and May 2018. In some cases, NRAs also submitted supplementary information, such as English summaries of their methodologies or other explanatory material.

- **Follow-up interviews of about one hour** – these were held with all but two NRAs (which chose to respond in writing alone), and in many cases were preceded by written questions that were requested by the NRAs to guide the discussions and to permit them to prepare for the interviews. The interviews were mostly held during May 2018. In a couple of cases, a second interview was needed as there were still significant ambiguities requiring clarification after the initial interview.

- **Summary of the collected information** – in order to keep the Report tractable, we do not present all the information that was collected in the questionnaires and interviews. Instead, we have chosen to focus on (critical) methodological issues and have largely excluded numerical information, except for where the Code seems to require that such data be provided, or where the numerical data assist in the comparison between regimes and NRA decisions (eg asset lives and cost of capital parameters). We have also produced 'country fact sheets' for each EU member state or NRA, which attempt to capture the main elements of the regulatory frameworks – these are included as an appendix to the Report (see Annex 16). The main body of Part II focuses on presenting comparative information on the approaches variously employed in the EU, and concludes with an overall assessment of the approaches together with a series of observations for further consideration by ACER and NRAs.

We wish to emphasise that the documentation of the current EU status described in this part of the Report is based entirely on the information provided by the NRAs to the Consultant. We have not been able, within the confines of this study, to verify the veracity of the information provided, except for running some 'logical checks' on the way that certain methodological questions were answered, exploring some responses during interview, and requesting clarifications through earlier drafts of this Report. We have therefore relied on the answers provided to us, and despite the process above there are some aspects that we are still uncertain about, but hopefully any remaining errors do not grossly misrepresent the broad approaches and practices applying in each jurisdiction.

9.2 Structure of Part II

The rest of this part of the Report is structured as follows:

- **Section 10** reviews the overall regulatory framework, covering the type of regulatory approach adopted, the approach to determining the cost of service, and the duration of both the regulatory period and the revenue review process
- **Section 11** focuses on how expenditure (both operating and capital) is generally assessed and determined
- **Section 12** describes issues regarding the regulatory asset base, including how an opening value was established when the prevailing regulatory regimes were first adopted and how the RAB is periodically updated, and it also covers depreciation of the asset base
- **Section 13** compares the approaches to determining the allowed rate of return including its constituent parts, and reviews whether separate financeability tests are conducted by NRAs
- **Section 14** reviews a number of miscellaneous regulatory mechanisms that might be employed to further adjust revenues, primarily to remain within the revenue cap and for incentive purposes
- **Section 15** employs the conceptual framework established in Section 8.3 (Part I) of this Report to provide a high-level assessment of EU methodological practices in setting allowed revenues for gas transmission, and offers some suggestions for further consideration by regulators as they continue to refine and develop their respective regulatory frameworks.

As already mentioned, Part II of the Report is supplemented by Annex 16 containing the country summary or fact sheets. Finally, we note that **in presenting information** in this section **we employ the full name of the various Member States but the information is generally set in the alphabetical order given by the two-letter EU country codes**.

10 Overall regulatory framework

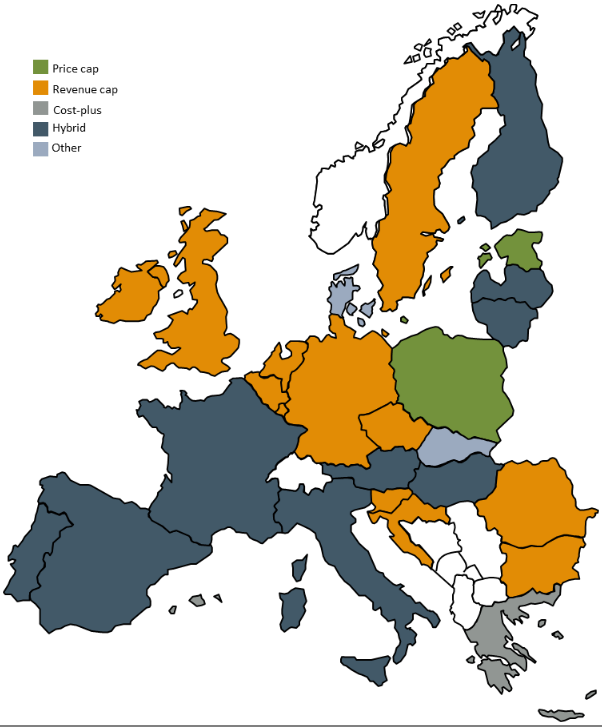
10.1 Type of regulation

The NRAs were requested to indicate the overall approach used to setting allowed revenues, distinguishing between the following methods:

- A **revenue cap** methodology, where the *revenue* for the TSO is set (that is, tariffs are subsequently adjusted for differences between forecasted and realised volumes to ensure the TSO earns the allowed revenue)
- A **price cap** methodology, where the maximum *tariff level* for the TSO is set by dividing the target revenues by forecasted volumes or capacity (that is, tariffs are not adjusted for differences between forecasted and realised volumes or capacity, and therefore TSO revenues vary with volumes or capacity)
- **Cost-plus and rate of return regulation** where revenue is generally set equal to historical costs and is adjusted to track cost changes or to maintain a reasonable allowed return, respectively
- **Hybrid** approaches entailing some combination of the above
- **Other** approaches that do not fit into the above categorisation and which the NRAs were asked to specify.

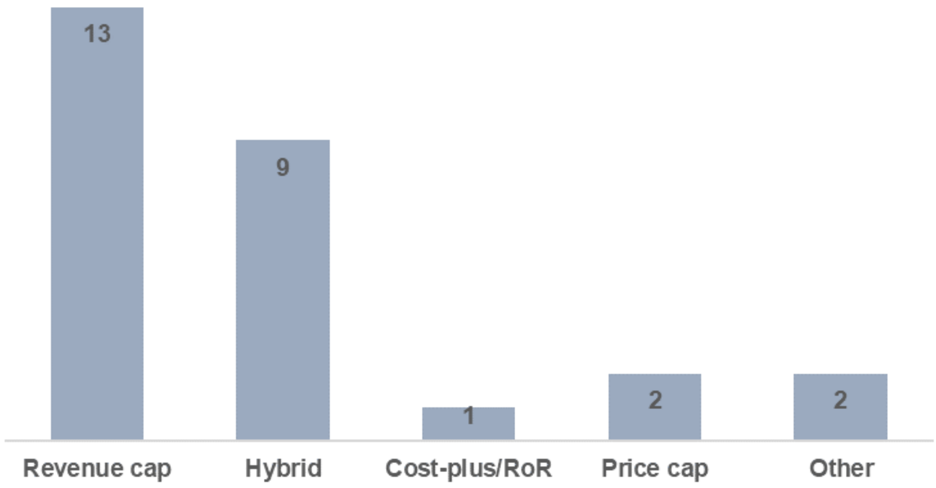
Figure 33 and Figure 34 show the approaches currently being utilised by the various NRAs.

Figure 33 Type of regulation (by country)



Source: NRAs, ECA analysis

Figure 34 Type of regulation (by type and number)



Source: NRAs, ECA analysis

Some key observations from the above figures are the following:

- **Revenue cap is the most common methodology employed**, being used in about half the jurisdictions (13 in total) and specifically in Belgium, Bulgaria, the Czech Republic, Germany, Croatia, Ireland, Luxembourg, the Netherlands, Romania, Sweden, Slovenia, Great Britain and Northern Ireland.

- **The next most common approach is a hybrid** – this is employed in nine countries (Austria, Spain, Finland, France, Hungary, Italy, Lithuania, Latvia, Portugal) and is almost invariably revenue cap for operating expenditures and cost-plus for capital expenditure. The exceptions are Italy and Portugal, which apply a price cap to the operating expenditure component – in the case of Portugal, this applies to 40% of opex.

- **One country employs cost-plus or rate of return regulation, while two countries respectively use price cap regulation and other mechanisms** – specifically, cost-plus is used by Greece, a price cap applies in Estonia and apparently in Poland[38], while Denmark and Slovakia have approaches that depart from the above 'typical' methods:

  - In **Denmark**, ***a variant of cost-plus*** is used where revenues and tariffs are set annually based on opex assessed as being efficient plus depreciation and financing costs. The latter consist of a cost of equity that is broadly equal to inflation, while debt costs are reflective of the terms allowed to the government-owned TSO for raising debt, namely, this is equal to the risk-free rate plus 0.15% for the bulk of the TSO's debt (~90%).

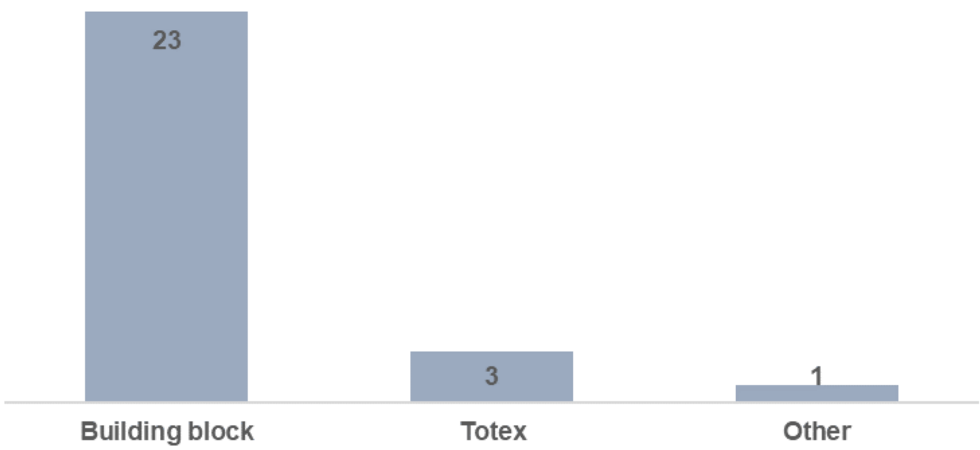
[38] The NRA characterises its regime as revenue cap, but given that as far as we were able to ascertain there is no revenue reconciliation, we assume the regime is price cap. The Czech Republic also uses price cap, but only for international transit (this is not shown in Figure 34 but explains the dual colour coding in Figure 33).

- In **Slovakia**, currently, ***tariff benchmarking*** is used (ie a comparison of tariffs charged on competing pipelines, which is not to be confused with statistical (cost) benchmarking which we describe elsewhere in this Report) for setting the maximum permitted tariffs. According to the NRA, this is done taking into account information on incurred costs and other relevant documents relating to business management. This approach, however, is being reviewed in the context of harmonising Slovakian legislation with the Gas Network Tariff Code and is therefore to be changed from 2022 when new tariff and regulatory periods commence (we are unable to pre-empt at this stage the methodology that is likely to be adopted for setting allowed or target revenues). At the present time, the NRA in cooperation with the TSO are in the process of the definition of the new price methodology, data collection and respective consultation preparation including final consultation in line with the terms and conditions of Articles 26, 27 and 28 of the Gas Network Tariff Code.

10.2 Approach to assembling the cost base

In most cases, irrespective of how allowed or target revenues are 'controlled' (which formed the subject of the previous sub-section), NRAs still require some methodology for assessing the cost of service for the TSOs to which the control shall apply. The broad approaches adopted are summarised in Figure 35 below.

Figure 35 Establishing the allowed cost of service (by approach and number)



Source: NRAs, ECA analysis

This demonstrates that:

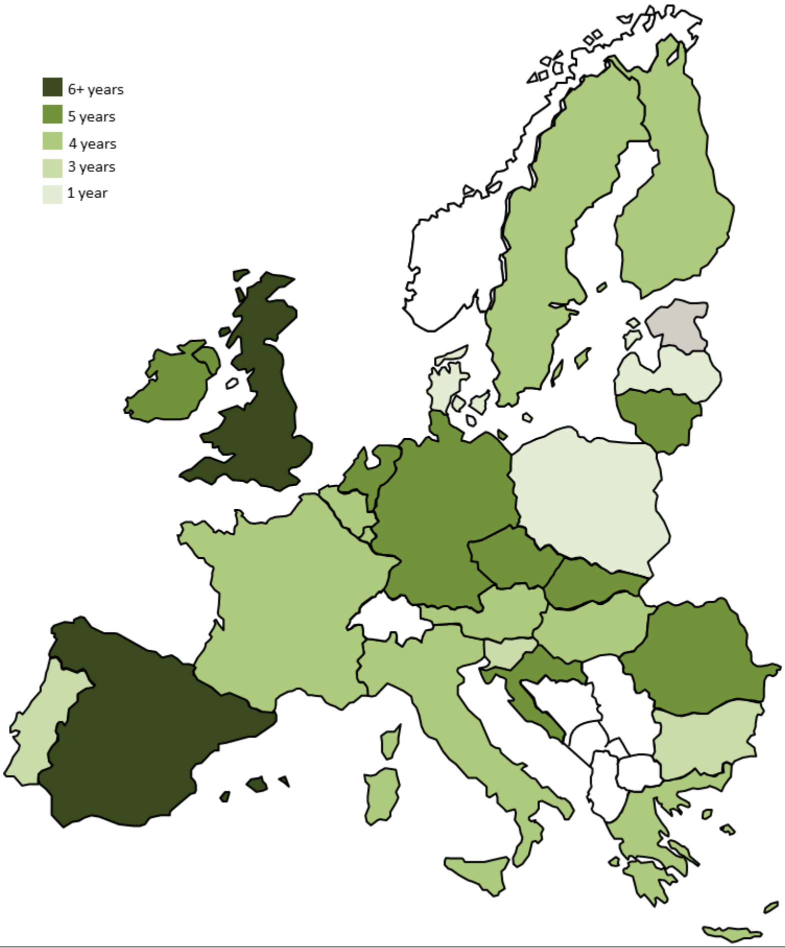
- The **building block approach is used by the vast majority of the NRAs** (23 out of 27), that is, they separately assess all cost components including operating expenditure and capital expenditure

- **A small number employ 'TOTEX' approaches**, where capital and operating expenditures are assessed in combination – this approach is used by three NRAs, specifically, in Germany, the Netherlands and Great Britain
- **One NRA employs neither of the above approaches** – this is Slovakia, given its current tariff benchmarking methodology to setting maximum tariffs. However, the NRA has stated that although it approves the maximum transmission tariffs based on a comparative tariff methodology, it does consider information on incurred costs and other relevant documents relating to business management (including comparison of costs for balancing services, costs related to the transmission of gas on the networks, depreciation and revenues for providing non-transmission services).

10.3 Regulatory period

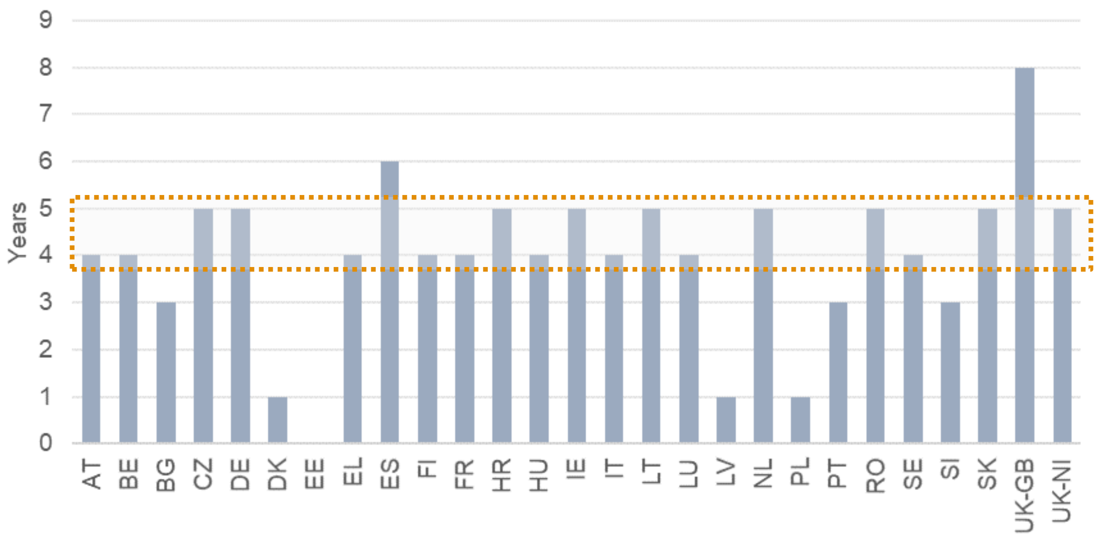
The duration of the regulatory period (being the time for which the allowed or target revenues are initially set, sometimes with predetermined adjustment mechanisms or triggers) varies across the NRAs as shown in Figure 36 and Figure 37 below, although **most countries have adopted four or five-year regulatory periods** (as highlighted by the dotted frame in Figure 37).

Figure 36 Duration of regulatory period (by country)



Source: NRAs, ECA analysis

Figure 37 Duration of regulatory period (years)



Source: NRAs, ECA analysis

More specifically, we note the following:

- The **most common regulatory period is:**
  - **Five years**, which has been adopted by **nine NRAs** - the Czech Republic, Germany, Croatia, Ireland, Lithuania, the Netherlands, Romania and Northern Ireland; Great Britain had recently departed from this but may revert to five years again in future; and
  - **Four years**, which is also currently the case for **nine NRAs** (Austria, Belgium, Greece, Finland, France, Hungary, Italy, Luxembourg and Sweden)
- **Three NRAs respectively employ three** (Bulgaria, Portugal, Slovenia) **and one-year** (Denmark, Latvia, Poland) **regulatory terms**
- **Another three NRAs have different terms** – Spain uses a six-year regulatory period, Great Britain currently has an eight-year term, while Estonia does not have a defined period. In Estonia, the price cap applies until such time as the TSO submits a new tariff application (or the NRA instigates a review on its own accord).

10.4 Revenue setting process

The last element of the overall framework we report on is the length of the revenue setting process, meaning the time taken from the moment the TSO submits its revenue and tariff proposals until a decision is made by the NRA for the allowed or target revenues. There is, as in other areas, considerable variability between the Member States although **most seem to be clustered around the four to six-month timeframe**. There are some NRAs, however, that reported much longer periods – Austria for example stated the process takes three years[39]. The other NRAs fall somewhere between these two ends of the spectrum.

A summary of the typical revenue setting periods employed by the NRAs is shown in Table 16. We note that in many cases the review process is not firmly set (in legislation, for example), so NRAs reported the time typically taken based on recent experience (although there might be a problem in drawing direct comparisons as some NRAs include the time taken to consult on aspects of the revenue setting methodology and collecting data, while others focus solely on the process for reviewing the cost information and setting the allowed revenues). In the case of Germany, the review process is *ad hoc* and variable, and is dependent on factors such as the quality of information submitted by individual TSOs, so the length of the review process varies between the many TSOs in that country – in the most recent period, the process took upwards of 24 months.

Table 16 Length of the revenue review and decision process

Time period	NRAs/countries
0 – 6 months	Belgium, Bulgaria, Estonia, Greece, Spain[40], Croatia, Hungary, Italy, Lithuania, Luxembourg, Latvia, Poland, Romania, Sweden, Slovenia, Slovakia
7 – 12 months	Portugal, Great Britain, Northern Ireland
13 – 18 months	Czech Republic, Ireland
19 – 24 months	Finland, France, Netherlands
>24 months	Austria, Germany
Ad hoc	Denmark

Source: NRAs, ECA analysis

[39] Within the four-year regulatory period applying in Austria, the revenue setting process for the following regulatory period is initiated approximately 36 months prior to its commencement. However, this is mainly for procedural reasons and the time is used to collect data for all the years of the regulatory period. The majority of the revenue setting process is concentrated in the 12 months before the start of the following regulatory period.

[40] Within the six-year regulatory period applying in Spain, the revenue setting process for the following regulatory period is initiated approximately 24-36 months prior to its commencement. However, this is mainly for procedural reasons and the time is used to collect data for all the years of the regulatory period. The majority of the revenue setting process is concentrated in the 12 months before the start of the following regulatory period.

11 Determining and setting expenditures

11.1 Cost assessment methods

In this section, we compare the broad methodological approaches adopted by NRAs for assessing projected costs of both an operational and capital nature. For both sets of expenditure, the NRAs were asked to identify which of the following methods are employed:

- **Bottom-up assessment**, which looks at the efficiency and reasonableness of individual cost items (for opex) or capital projects or programmes (for capital expenditure)
- **Top-down assessment** (applies just to opex), which abstracts from individual cost items and, instead, focuses on broad cost categories
- **TOTEX approach**, where operating and capital expenditures are not accounted for separately and are assessed in combination; this is normally used with cost benchmarking
- **Cost benchmarking**, where assessments relate allowed costs to benchmarks established by reference to comparator TSOs.

These assessment methods are not necessarily mutually exclusive and can be used in combination (as indeed they are by some NRAs[41]).

11.1.1 Operating expenditure

The NRA responses regarding assessments of operating expenditure are summarised in Figure 38 and Figure 39 below. We note that where two approaches or methodologies are used, the map here (and in subsequent figures) shows these countries with a striped pattern (with the stripes in the colour of one of the two mechanisms employed), while countries using three or more methods are shown as a separate category.

As demonstrated in the figures below:

- **Bottom-up assessments dominate as an analytical approach to assessing opex** – this is used by 17 NRAs, with more than half of these (nine) relying exclusively on such assessments (Austria, Bulgaria, Greece, Luxembourg, Latvia, Poland, Romania, Slovenia and Northern Ireland) and the remainder (Germany, Estonia, Croatia, Hungary, Ireland, Lithuania, Portugal and Great Britain) using them in combination with other methods, usually top-down assessments and/or cost benchmarking.
- **Top-down assessments are also prevalent** – 11 NRAs employ such methods in total, with five apparently relying on this method alone (Belgium, Denmark, Spain, Finland and Sweden), while the rest (Germany, Estonia, Croatia, Ireland,

[41] This explains why the total number of NRAs in the bar graphs that follow exceeds 27.

Lithuania and Portugal) use this in conjunction with other approaches. However, we have not been able to ascertain the degree to which this analysis also employs external efficiency benchmarks to sense-check the top-down assessments.

- **TOTEX is used (as expected) by the same countries that characterised their overall approach as such**, that is, Germany, the Netherlands and Great Britain. France, however, also employs a TOTEX approach, but only for a subset of TSO expenditure related to IT, buildings and vehicles.

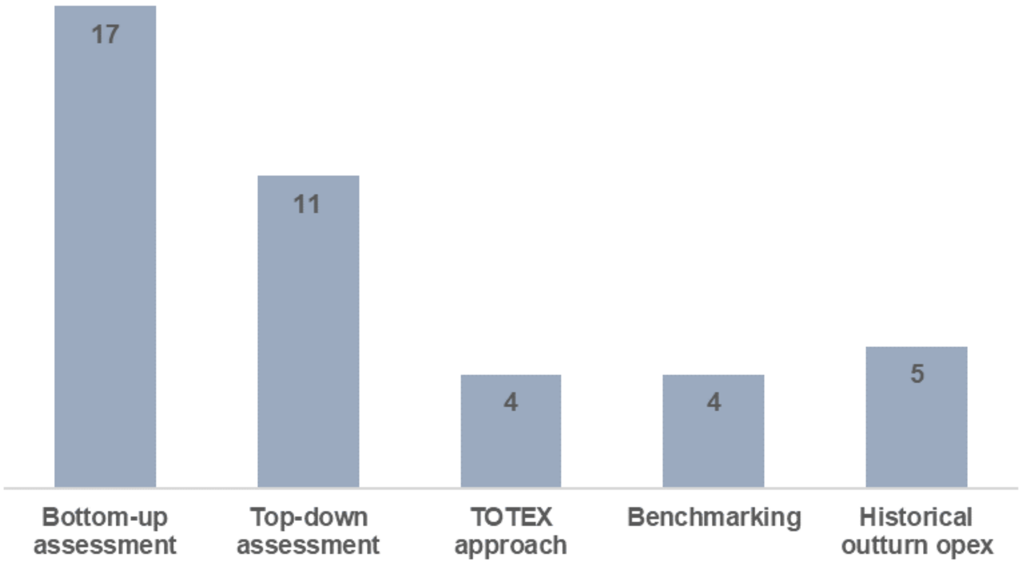
- **Cost benchmarking is generally uncommon, being used by just four NRAs** – as anticipated, statistical benchmarking is employed by the three countries adopting TOTEX approaches (Germany, the Netherlands and Great Britain), but it is also used as a sense-check for cost assessments using some of the above-mentioned methods by Hungary (but only in limited circumstances ie in relation to employee and rental costs).

- **Five NRAs** (the Czech Republic, Croatia, Spain, Hungary and Italy) indicated that they **use an alternative approach** which was not pre-defined in the questionnaire, but which has similarities across these countries; we have labelled this **"historical outturn opex"** in the figures below. Broadly, this approach entails setting future operating expenditures at levels that are commensurate with past or realised expenditures, provided that these are considered to be efficient and, in most cases, after making adjustments for extraordinary costs that were incurred in the reference or base year(s) used for this purpose, allowing for inflation and adjusting for growth in the network.

Figure 38 Cost assessment methods for operating expenditures (by country)

Source: NRAs, ECA analysis

Figure 39 Cost assessment methods for operating expenditures (by type and number)



Source: NRAs, ECA analysis

11.1.2 Capital expenditure

Figure 40 and Figure 41 summarise the corresponding information for the assessment of capital expenditure. Key takeaways from these figures are:

- As with opex, **bottom-up assessments are the main tool employed by NRAs for assessing the reasonableness of TSOs' capital expenditure proposals – such assessments are employed in 19 cases**, mostly as the single analytical approach, with only Spain and Great Britain complementing such assessments with other mechanisms (benchmarking for Spain, and TOTEX and benchmarking for Great Britain). In Portugal, if there are significant cost overruns, the Portuguese NRA stated it might investigate further.

- **TOTEX (as before) is used in Germany, the Netherlands and Great Britain**, with France also employing a TOTEX approach for a subset of expenditure (IT, buildings and vehicles).

- **Cost benchmarking is employed by the three TOTEX countries (Germany, the Netherlands and Great Britain)**, and also Spain which partly uses benchmarked costs for setting allowances.

- **Five countries characterised their approaches as 'other' or 'non-applicable'**:

  - In Finland and Sweden, capital expenditure is assessed *ex post* for its efficiency (but it is unclear how such assessments are undertaken)

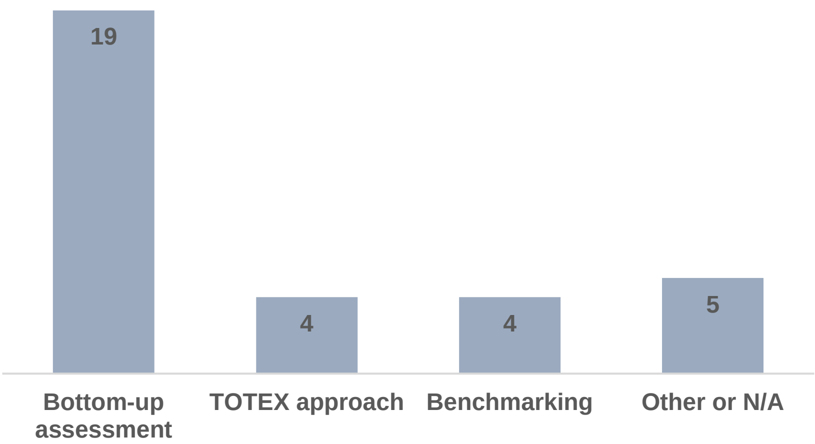
  - In Romania, capital expenditure is assessed as part of the approval process for the 10-year network development plan (and therefore is not considered further when setting allowed revenues) – we should note that other countries also employ a similar approach (for example, the Greek NRA assesses both investment needs and costs as part of the approval process for the 10-year network development plan and then, given the cost-plus nature of the regime, realised capex spend enters the RAB), but these NRAs have characterised their approach as 'bottom-up', so there could be some overlap between these two categories

- Latvia applies a cost-plus regime and therefore no *ex ante* assessments of capital expenditure are undertaken
- Slovakia, as explained in section 10.1, uses a tariff comparison approach and therefore this question is not relevant to its circumstances.

Figure 40 Cost assessment methods for capital expenditures (by country)

Source: NRAs, ECA analysis

Figure 41 Cost assessment methods for capital expenditures (by type and number)



Source: NRAs, ECA analysis

11.2 Use of cost pass-throughs for opex

Notwithstanding the almost universal application of revenue or price caps for opex, and therefore of incentive regulation, an issue arises as to whether elements of opex are still considered by NRAs to be outside the control of the TSOs and are therefore treated as full or partial pass-through (incentives are generally only effective where the TSOs can manage their expenditure). Based on the questionnaire responses, it is evident **that most of the NRAs do treat some opex components as pass-through**. The only **exceptions** to these are the following seven NRAs:

- Greece and Latvia given that they operate under cost-plus regimes in any case so effectively all costs are passed through
- Slovakia for which this matter is irrelevant given its tariff benchmarking approach
- The Czech Republic, Croatia, the Netherlands[42] and Portugal where no differentiation is made between controllable and uncontrollable operating costs.

Among those NRAs employing pass-through mechanisms, there is considerable variability in the cost categories to which these apply. **The most common and almost universal costs recognised as pass-through are fuel gas (the cost of gas consumed in compressors) and government taxes and duties**. Depending on the country, some other common pass-through items are council rates, licence fees and other regulatory costs, non-wage payroll costs and bad debts.

[42] There are some exceptions made to the general rule in the Netherlands - if costs are very difficult to estimate and this leads to an uncontrollable risk for the utility, the NRA does make an exemption.

11.3 Efficiency factors

The NRAs were requested to indicate whether cost forecasts or allowed expenditures include efficiency or productivity improvements, whether embedded within the cost forecasts/allowances themselves (eg where these are based on cost benchmarks) or are set over and above the 'base' cost allowances after assessing the reasonableness of TSO cost submissions (as opposed to applying an efficiency or productivity factor at the level of the overall price or revenue control). **In the case of capital expenditures, the use of efficiency factors is not common; it is generally limited to those NRAs applying a TOTEX approach** and therefore efficiencies are embodied in the analysis itself (ie in Germany, the Netherlands and Great Britain). Beyond these, efficiency considerations for capital expenditure are reflected in Spain, where allowances are partly based on 'reference unit costs' determined under a recent benchmarking/costing study.

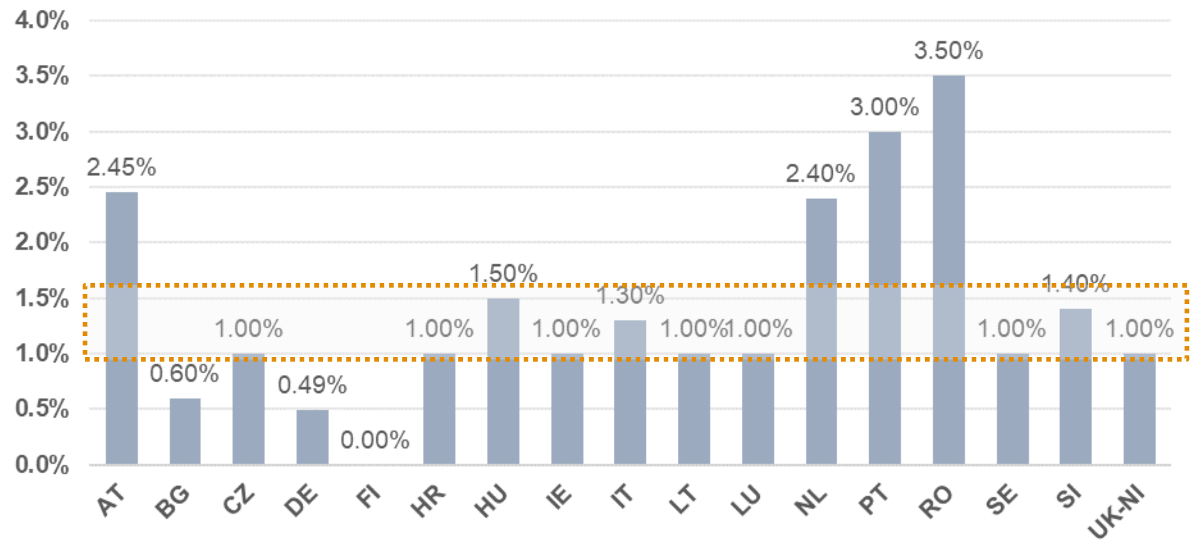
In the case of opex, the majority of NRAs (19 out of 27) do apply efficiency factors. The countries that employ efficiency factors for operating expenditure versus those that do not are shown below in Table 17, while the corresponding efficiency factors adopted in the most recent NRA decisions appear in Figure 42.

Table 17 Employment of efficiency factors when setting opex allowances

NRAs that employ efficiency factors	NRAs that do not employ efficiency factors
1. Austria	1. Belgium
2. Bulgaria	2. Denmark
3. Czech Republic	3. Estonia
4. Germany	4. Greece
5. Finland	5. Spain
6. France	6. Latvia
7. Croatia	7. Poland
8. Hungary	8. Sweden
9. Ireland	9. Slovakia (not applicable)
10. Italy	
11. Lithuania	
12. Luxembourg	
13. Portugal	
14. Netherlands	
15. Romania	
16. Sweden	
17. Slovenia	
18. Great Britain	
19. Northern Ireland	

Source: NRAs, ECA analysis

Figure 42 Opex efficiency factors (%)[43]



Source: NRAs, ECA analysis

As shown in Figure 42 above, **most opex efficiency factors are in the 1%-1.5% range**. Four countries have higher efficiency factors of 2%-3.5%, while Bulgaria employs a lower factor of 0.6%[44]. In the case of Finland, the efficiency factor was 0% for the latest revenue control because of additional tasks undertaken by the TSO (but was previously 1% per year).

We must emphasise that the efficiency factor shown for the Netherlands is not comparable to the rest. As far as we are able to ascertain, for all countries (except the Netherlands) the factors used are effectively for 'relative efficiency' (or what is termed 'static efficiency' in the Netherlands) - this represents the improvement needed to close the gap between a TSO's current level of efficiency and that represented by the most efficient firms currently (defined as those firms lying on the 'efficiency frontier'). **In the case of the Netherlands (and for Germany and Great Britain), this 'catch-up efficiency' is embedded in the cost allowances or allowed revenues[45]**. In fact, in Germany, the efficiency factor is TSO-specific, and each TSO must eliminate any efficiencies compared to the industry benchmark within a regulatory period. However, **in the Netherlands, productivity growth (or what is termed 'dynamic efficiency') is also considered** (over and above static efficiency) **and the 0.6% factor refers to this element, representing the expected movement of the efficiency frontier over time**, as new technologies and work practices become available[46]. Germany also applies a productivity factor, currently set at 0.49% per year.

[43] Of those countries that employ efficiency factors, we do not have data for Great Britain. In the case of Germany, the factor shown is that for the frontier shift alone. For the Netherlands, the factor has been calculated as the compound annual rate of 100 to 88.7 over five years and a frontier shift of 0.6% is also assumed.

[44] France (not shown) reported efficiency factors of 0.74% for GRTgaz and 1.04% for TIGF **above** inflation. This is because a growth factor is included; we were unable to ascertain the 'pure' efficiency factor (ie net of the growth factor).

[45] The Netherlands uses a static efficiency factor from two benchmarks and apples a margin of 5%, since some of the data is relatively dated. The TSO is benchmarked against the German TSOs: 78.9+ 5=83.9% and against 21 other European TSOs, which has a score of 81.6+5=86.6%.

[46] The NRA decision is currently under challenge and it appears that this factor might changes as a result of the appeal.

12 The regulatory asset base

Key reporting requirements under Article 30(1)(b)(iii) of the Gas Tariff Network Code are:

- methodologies used to determine the initial value of the assets
- methodologies used for valuing assets periodically
- the types of assets included in the regulated asset base
- depreciation periods by asset type.

This section reports on these and related issues, all of which impact on the treatment of the regulatory asset base (or RAB).

12.1 Setting the opening asset value

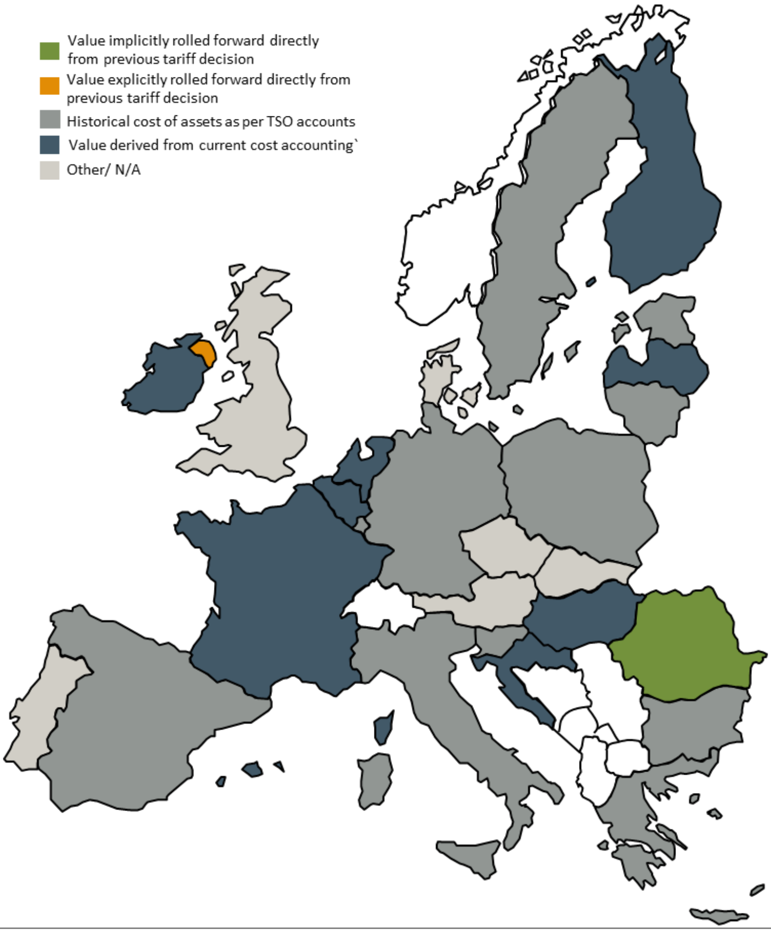
Figure 43 overleaf summarises the methodologies that were employed by the NRAs (or other authorities) for establishing an opening asset value when the current regulatory frameworks were originally established. We note the following:

- The most common methodologies employed were historical cost accounting and current (or replacement) cost methodologies:
  - **Historical cost accounting was used in most cases (11 countries) for setting opening asset values**, specifically in Bulgaria, Germany, Estonia, Greece, Spain, Italy, Lithuania, Luxembourg, Poland, Sweden and Slovenia
  - **The next most common methodology was a (current cost) accounting or valuation methodology – this was employed in eight cases**, namely in Belgium, Finland, France, Croatia, Hungary, Ireland, Latvia and the Netherlands. The current cost methodologies employed vary between these countries:
    - Belgium, Hungary and Latvia used a replacement cost concept
    - Finland refers to a ‘net present value’ approach
    - In France the opening asset value was established by a commission headed by the academic Houri, but the methodology employed is not public (see the France country sheet for more details)
    - In Croatia, revaluation of the assets was undertaken in 2001 as part of the unbundling of the TSO from VIU (INA Ltd) – this was set based on a ‘fair value’ revaluation methodology, with the study undertaken by professionally qualified valuers and was confirmed by a statutory auditor
    - Ireland and the Netherlands employed historical cost indexation

❑ **Of the other methodologies pre-specified in the questionnaire**:

- ❑ In Romania, the value rolled forward from the value *implicitly* used in previous tariff/revenue decisions (ie the value 'backed out' from the tariff levels prevailing at the time)
- ❑ In Northern Ireland, the value rolled forward from the value *explicitly* used in previous tariff/revenue decisions.

Figure 43 Methodologies used for establishing opening asset values (by country)



Source: NRAs, ECA analysis

❑ **Several NRAs (five) indicated that 'other' approaches were used** and characterised or described their circumstances as follows:

- ❑ Austria – the debt-financed component was valued at historical cost and the equity component using replacement values
- ❑ Czech Republic – the RAB was set at a level that ensured the prevailing level of profitability
- ❑ Denmark – although a valuation was conducted, this is not treated as a RAB; it appears that an equity value was established that was equivalent to the net assets at the time and this value has been preserved over time in real terms through inflation indexation

- Portugal – the opening asset value was established by the Government, based on revaluation rates defined by the Government itself

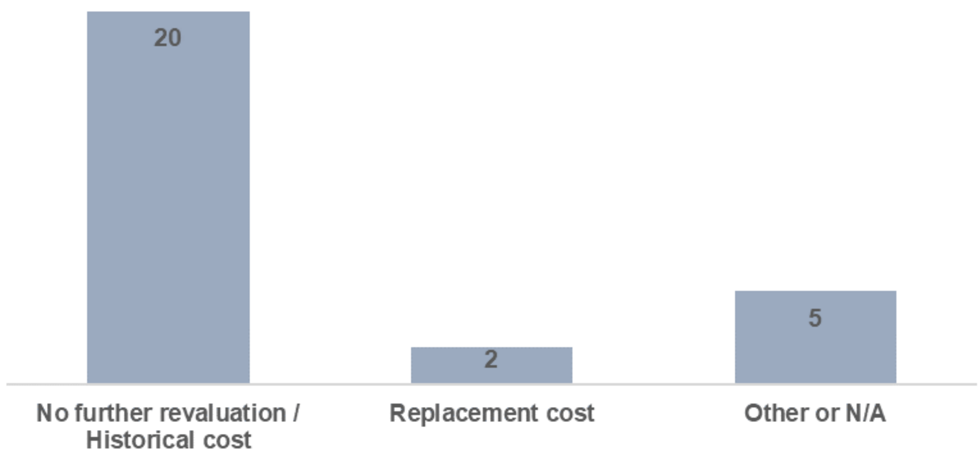
- Great Britain – an independent valuation was undertaken at the time of privatising the vertically-integrated British Gas (which included the transportation component as only one element of the whole).

12.2 RAB valuation methods

Irrespective of how the opening value of the RAB was established, there is a separate question regarding the updating of the RAB over time. In general terms, the valuation options are either to roll in investments (and deduct depreciation) without any further adjustments or revaluation, or to periodically revalue using a current cost methodology.

The vast majority of NRAs (20 out of 27) adopt the former approach, ie there is no further revaluation of the RAB (see Figure 44), irrespective of whether a current cost methodology was used to establish the opening value. We note that some in this group do index the RAB for inflation, but this is because it is needed for reasons of consistency given that they employ a real WACC (that is, indexation is not undertaken as an approximate approach to setting asset values at current costs).

Figure 44 Methodologies for periodically updating the RAB (by type and number)



Source: NRAs, ECA analysis

As shown in the figure, **two NRAs use a replacement cost methodology for the periodic revaluation of the asset base**; these are Hungary and Latvia. Finally, there are **five NRAs** that **use other approaches** or for which the issue of asset valuation is not relevant:

- Austria indexes only the equity portion of the RAB to inflation (because it sets a separate cost of equity in real terms, but a nominal cost of debt)

- Denmark and Slovakia, as explained in section 10.1, apply unique revenue setting regimes and therefore do not separately account for a RAB

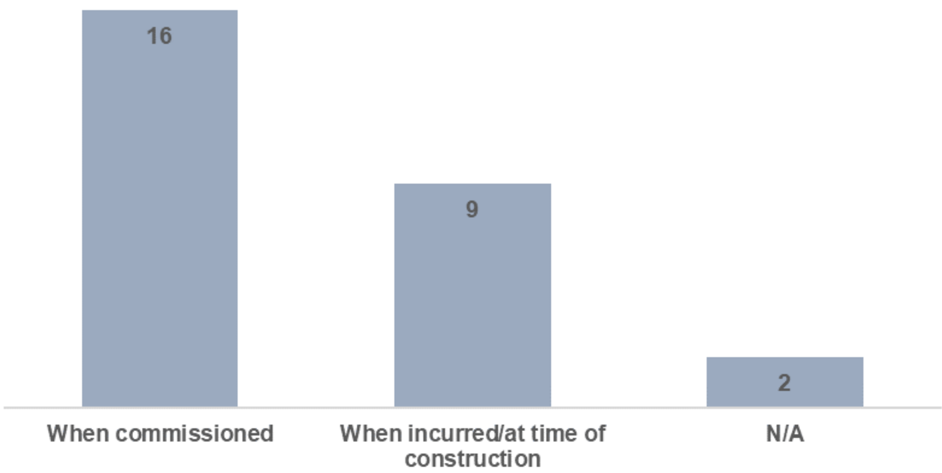
- Finland states that the RAB is calculated every year using "average unit prices and average age-information"
- The German regulatory system distinguishes between old assets (capitalised before 2006, the year that regulation commenced) and new assets (capitalised in and after 2006). These are valued and depreciated differently. New assets (2006 onwards) are depreciated based on historical costs. The share of old assets (pre-2006) financed by debt (minimum 60%) is depreciated based on historical costs. The share of old assets financed by equity (up to a maximum of 40%) is depreciated based on the assets´ replacement values. To calculate these replacement values, historical costs are inflated using price indices.

12.3 Timing of when assets enter the RAB

Another matter impacting on the value of the RAB (and therefore, in most cases, allowed returns and revenues) is the timing of when assets or capital expenditure is recognised in the RAB (see the discussion in section 5.2.2). Figure 45 below and Figure 46 overleaf summarise the approach adopted by the NRAs. As depicted in the figures:

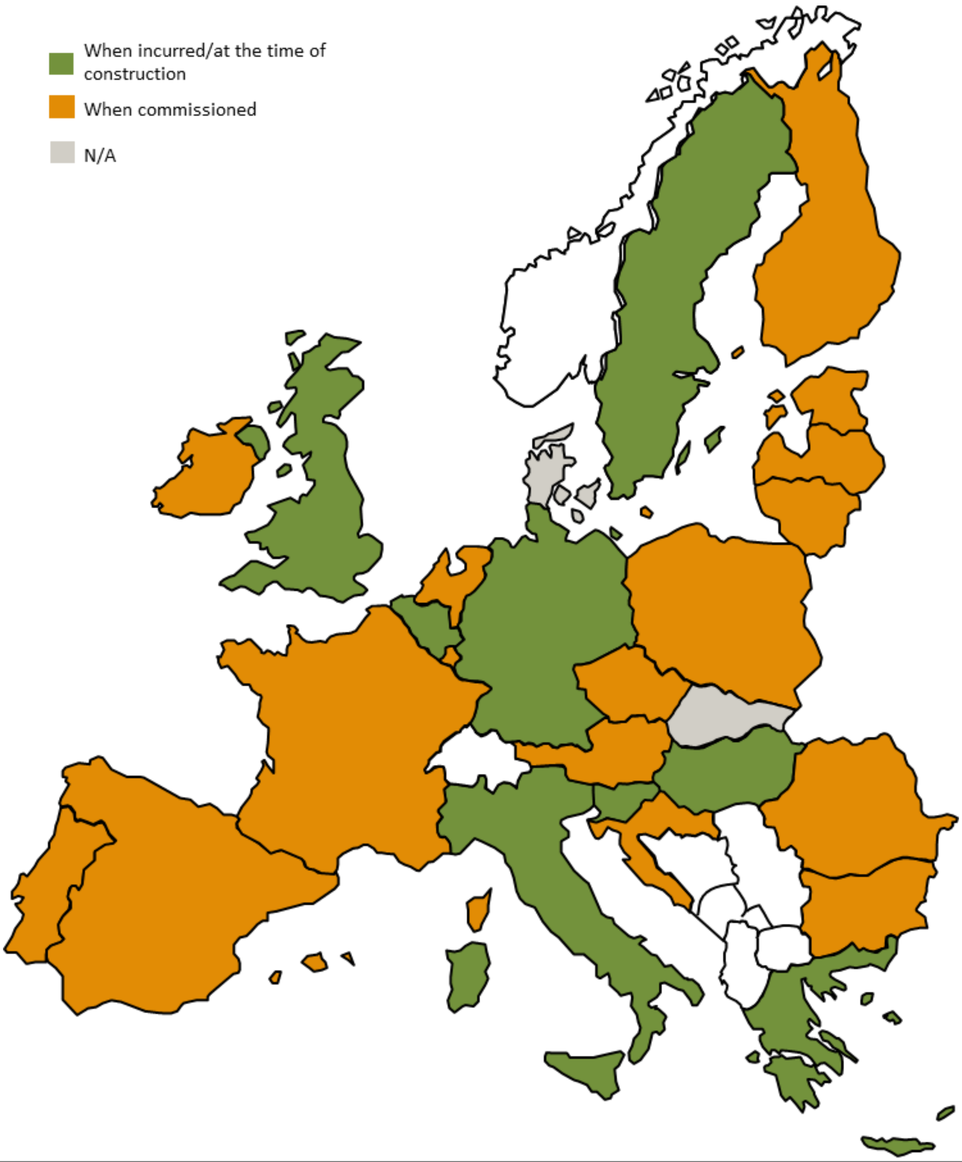
- both approaches are used extensively, although **in most cases (16 NRAs) assets are recognised in the RAB upon their commissioning** – this applies to Austria, Bulgaria, the Czech Republic, Estonia, Spain, Finland, France, Croatia, Ireland, Lithuania, Luxembourg, Latvia, the Netherlands, Poland, Portugal and Romania
- **capital expenditure enters the RAB as spent in nine regimes** – Belgium, Germany, Greece, Hungary, Italy, Sweden, Slovenia, Great Britain and Northern Ireland
- the issue is **irrelevant for two NRAs** – in Denmark and Slovakia because, as already discussed, there is no RAB used for revenue setting.

Figure 45 Timing of rolling investments into the RAB (by approach and number)



Source: NRAs, ECA analysis

Figure 46 Timing of rolling investments into the RAB (by country)

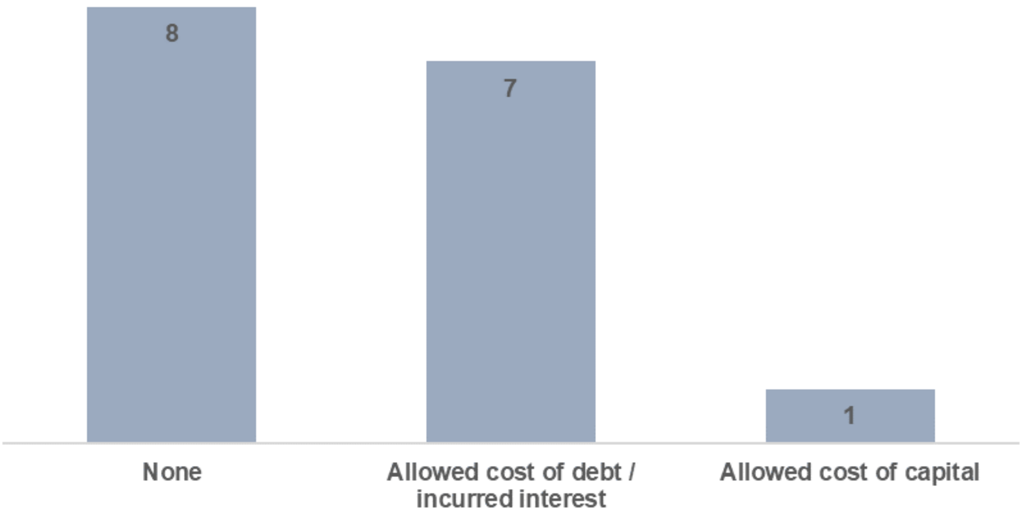


Source: NRAs, ECA analysis

For those 16 NRAs that recognise investments once they are commissioned, an added consideration is whether to recognise any financing costs for the construction period leading up to their commissioning. In response to this question (see Figure 47):

- **eight NRAs stated that financing costs are not recognised** – this applies to Austria, Bulgaria, the Czech Republic, Estonia, Croatia, Lithuania, Luxembourg and Poland
- **another seven NRAs use the allowed cost of debt for rolling up the asset values or recognise the interest costs actually incurred which are usually capitalised into the book value of the assets** – this is the case for Spain, Finland, France, Ireland, Latvia, Portugal and Romania
- **only the Netherlands employs the allowed WACC for rolling up the value of the assets.**

Figure 47 Rate applied for rolling assets into the RAB upon commissioning



Source: NRAs, ECA analysis

12.4 *Ex post* reviews of capital expenditures

Table 18 below shows the countries that undertake *ex post* reviews of capital expenditure versus those that do not, before assets are rolled into the RAB. **The countries are largely evenly split between those that do and do not conduct *ex post* reviews of investments**.

For those that do not undertake reviews, the rationale in many cases is that investments are generally approved through network development plans and hence do not need to be assessed again for need, while other mechanisms (such as required tendering) serve as sufficient disciplines for containing costs.

Among those that do conduct reviews, these are generally undertaken on an *ad hoc* basis and there are no prespecified limits on the scope and materiality of the reviews or defined procedures for how these are undertaken. However, the reviews are mostly focused on 'large' investments (however defined) and where costs deviate substantially from those estimated and/or budgeted at the time of the network development plans. Having said that:

- Bulgaria, Croatia, Ireland and Northern Ireland review both investment need and costs
- France, on the other hand, reviews costs alone and focuses on significant investments, defined as those exceeding €20 million
- In Italy, the possibility of *ex post* review of costs is available, but this has not been employed to date in practice
- In Luxembourg, *ex post* reviews are undertaken for investments exceeding €500,000 or which have a cross-border impact. The reviews compare both forecasted versus realised costs, and planned versus realised durations.

Table 18 *Ex post* reviews of capital expenditure

NRAs undertaking *ex post* reviews	NRAs that do not undertake *ex post* reviews
1. Bulgaria	1. Austria
2. Denmark	2. Belgium
3. Greece	3. Czech Republic
4. Finland	4. Germany
5. France	5. Estonia
6. Croatia	6. Spain
7. Ireland	7. Hungary
8. Italy[47]	8. Lithuania
9. Luxembourg	9. Latvia
10. Poland	10. The Netherlands
11. Portugal	11. Romania
12. Great Britain	12. Sweden
13. Northern Ireland	13. Slovenia
	14. Slovakia

Source: NRAs, ECA analysis

12.5 RAB composition

Several survey questions explored whether particular asset classes and other related parameters are included in the RAB for revenue setting purposes.

As expected, pipelines, gas receiving stations, compressor stations, control stations, metering stations, and meter and regulation stations at the interface with the distribution network are all commonly part of the RAB in most or all jurisdictions.

However, as shown in Table 19, there was **much less consistency in relation to linepack, large customer connection assets and working capital. For all three elements, most countries exclude these from the RAB**, but a significant number do include them, particularly connection assets and to a lesser degree working capital and linepack.

[47] Not undertaken to date in practice, although the possibility exists.

Table 19 Inclusion of linepack, connection assets and working capital in the RAB

Item	Included	NOT included
Linepack	**9 NRAs**: Belgium, Bulgaria, Germany, Spain, Croatia, Hungary, Italy, Latvia, the Netherlands	**18 NRAs**: Austria, Czech Republic, Denmark, Estonia, Greece, Finland, France, Ireland, Lithuania, Luxembourg, Poland, Portugal, Romania, Sweden, Slovenia, Slovakia (n/a), Great Britain, Northern Ireland
Customer connection assets	**13 NRAs**: Belgium, Germany, Estonia, Spain, France, Croatia, Hungary, Ireland, Lithuania, the Netherlands, Poland, Slovenia, Northern Ireland	**14 NRAs**: Austria, Bulgaria, Czech Republic, Denmark, Greece, Finland, Italy, Luxembourg, Latvia, Portugal, Romania, Sweden, Slovakia (n/a), Great Britain
Working capital	**7 NRAs**: Belgium, Bulgaria, Germany, Estonia, Greece, Finland, Italy	**19 NRAs**: Austria, Czech Republic, Denmark, Spain, France, Croatia, Hungary, Ireland, Lithuania, Luxembourg, Latvia, Netherlands, Poland, Portugal, Romania, Sweden, Slovenia, Slovakia (n/a), Great Britain, Northern Ireland

Source: NRAs, ECA analysis

Regarding working capital, for those countries where it is included in the RAB, **each country determines the working capital allowance differently**:

- ❑ Belgium applies a formula reported as "1/12 * new investment for the year + 1/12 * purchases for the year + 50% * dividends"
- ❑ Bulgaria uses the 45-day approach, that is, where the TSO's allowance is set equal to one-eighth (1/8 of a year ≈ 45 days) of its annual operating and maintenance expenses
- ❑ In Germany, for receivables, the average time difference between billing and when revenue is collected is used, provided receivables are efficiently managed, and cash is also included if a TSO can prove that it is necessary to manage cashflows
- ❑ In Estonia, the allowance is calculated as 5% of the last three years' turnover
- ❑ Greece applies the balance sheet method, that is, where the allowance is set equal to current assets minus current liabilities
- ❑ Finland treats the working capital separately from the RAB, which we understand to mean that it is not remunerated at the allowed WACC but at some other(lower) rate
- ❑ In Italy, working capital is assumed to be 0.8% of gross investment capital.

The treatment of linepack also varies among those countries that do include it in the RAB:

- ❑ Bulgaria has two categories of linepack - 90% is treated as fixed (non-depreciating) and 10% is treated as a depreciating asset (and therefore has a declining value)

- Germany and Italy capitalise the linepack with the asset and depreciate it at the same rate as the pipelines
- Spain, Croatia and Hungary use a fixed quantity, which is valued
  - In Spain, using the wholesale gas price index at the time of the commissioning of the installation
  - In Croatia, at the actual TSO purchasing cost (subject to NRA review of its reasonableness)
  - In Hungary, as calculated by the TSO
- Latvia and the Netherlands set a variable amount depending on the rates of pipeline intake and offtake, which is then valued using the wholesale gas price index.

12.6 Depreciation methodology and asset lives

The depreciation methodology is one of two areas (the other is the cost of equity) where there is broad consensus among the NRAs, in that **all jurisdictions apply the straight-line methodology** (that is, asset costs are spread evenly over the defined useful life of the assets). The only exception to this general rule are Belgium and Great Britain which use declining balance (or accelerated) depreciation for a “limited number of installations” and for older assets, respectively.

However, while the methodology employed for depreciation is the same, **the defined asset lives vary widely among the EU member states** and NRAs. Table 20 over the page shows the asset lives adopted for some of the main gas TSO asset classes, namely pipelines, compressors, controllers and SCADA/telecoms. **Given that most NRAs also stated that depreciation is not used for the purposes of reprofiling revenues or tariffs, these ostensibly represent different views about the useful life of the assets**. As shown in the table:

- **Pipeline** asset lives range from **30 to 90 years**, with most NRAs clustered around 40-50-year lives
- **Compressor** asset lives range from **12 to 65 years**, with most NRAs employing 20-30-year lives
- The asset lives of **controllers and metering stations** range from **9 to 45 years**, with perhaps 20-30 years representing the most common range (but there is much variation around this)
- Asset lives for **SCADA and telecom equipment** range from **4 to 30** years, with most in the 5-10-year range.

Table 20 Assumed asset lives (years)

Country	Pipelines	Compressors	Controllers, metering stations	SCADA, telecom
Austria	30	12	12	12
Belgium	50	33	33	5 (SCADA) 10 (telecom)
Bulgaria	35	15	15	-
Czech Republic	40	20	10	10
Germany	45 – 65	15 – 30	45	15 – 20
Denmark	35	35	35	-
Estonia	50	n/a	30	-
Greece	40	40	40	5
Spain	40	20	30	10
Finland	50 – 65	65	20	-
France	50	30	30	10
Croatia	35	35	35	-
Hungary	50	20	20	25
Ireland	50	25	15	-
Italy	50	20	20	5
Lithuania	55	20	9	4
Luxembourg	40	40	40	10
Latvia	50 – 60	n/a	20	5 – 30
The Netherlands	55	30	30	5 – 15
Poland[48]	40	25	25	5
Portugal	35	-	-	-
Romania	25 – 40	40	10 – 20	-
Sweden	90	n/a	40	8
Slovenia	35	5 – 15	15	6
Slovakia	n/a	n/a	n/a	n/a
Great Britain	45	45	45	-
Northern Ireland	43	n/a	20	-

Source: NRAs, ECA analysis

[48] We have inferred the asset lives from a generic accounting classification that was submitted in the questionnaire response.

13 The weighted average cost of capital

Another matter singled out by the Gas Tariff Network Code that must be reported by ACER is the "cost of capital and its calculation methodology". Accordingly, in this section we focus on how NRAs have set the allowed or target return on capital in their two most recent revenue determinations (where relevant). We explore the methodologies adopted and also report on the various parameters that underpin the WACC calculation. In the last sub-section, we briefly examine the degree to which NRAs undertake separate financeability assessments to ensure that TSOs can fund their activities.

13.1 WACC basis

As discussed in section 6.1 of Part I of the Report, the weighted average cost of capital can be set in pre-tax, post-tax or vanilla terms and on either a real or nominal basis. A variety of approaches are used among the EU NRAs, as summarised in the map of Figure 48 below. More specifically, the following approaches have been adopted:

- **Pre-tax nominal WACC is the most common, used by 12 NRAs** – Belgium, Bulgaria, the Czech Republic, Greece, Spain[49], Finland, Croatia, Lithuania, Luxembourg, Poland, Portugal[50] and Slovenia
- **Pre-tax real regimes are the next most prevalent, used in six countries** – France, Hungary, Ireland, Italy, the Netherlands and Sweden
- **A vanilla WACC is used in three jurisdictions** – in Great Britain and Northern Ireland where it is set in real terms, and in Estonia which employs a nominal vanilla WACC
- **Two NRAs employ a post-tax nominal regime** – Latvia and Romania
- **Four countries have other approaches**, as follows:
    - Austria, Germany and Denmark all treat the cost of equity and debt separately
        - Austria sets a pre-tax real cost of equity and a pre-tax nominal cost of debt
        - In Germany, actual debt costs are recognised in allowed revenues subject to assessing their reasonableness against interest costs that are "customary in the financial markets for similar borrowings"; the cost of equity is determined employing a conventional CAPM

[49] We note that Spain does not have a WACC strictly speaking. Instead, the NRA uses an interest rate of 5.09%, which is calculated based on the price of money in Spain for 10 years plus 0.5%.

[50] In Portugal, due to the uncertain and financially unstable environment since 2011, the rate of return is updated *ex-post* (each 'gas year') in order to reflect the evolution of financial market conditions. The WACC for the TSO, applied since July 2013, is indexed to the Portuguese 10-year bond benchmark and depends, in each year, on its evolution, with a cap and a floor.

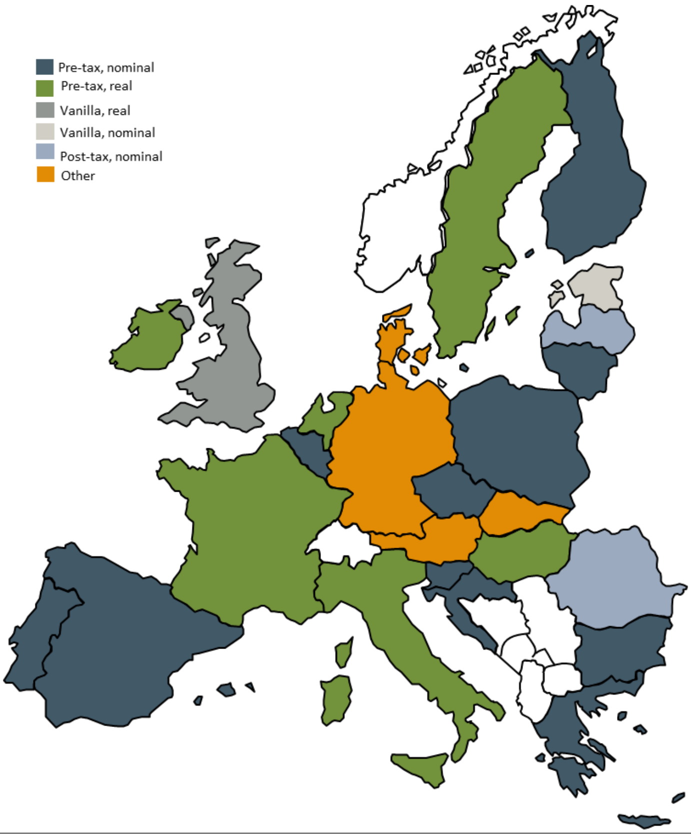
approach, however given that 'old' (pre-2006) assets are valued at replacement cost, the cost of equity is set in real terms, whereas for 'new' assets (2006 onwards) it is set in nominal terms (both costs are in pre-tax terms)

- Denmark sets the cost of equity broadly equal to inflation to maintain the monetary value of the assets. Regarding debt costs, the government-owned TSO participates in the Danish Government's relending system with beneficial interest rates on government loans which constitute close to 90% of its reported interest-bearing debt.

- Slovakia does not explicitly set an allowed rate of return, relying on tariff benchmarks for setting allowed tariffs.

A final observation that can be made is that **nominal regimes are much more prevalent than real** (15 versus eight) and **most regulators prefer to work in pre-tax terms** (18 versus five) thereby abstracting from formal tax calculations.

Figure 48 WACC basis (by country)



Source: NRAs, ECA analysis

13.2 WACC values

Table 21 and Table 22 below present the WACCs reported by the NRAs as having been adopted in their most recent regulatory decisions and in the preceding regulatory period, respectively. The arrows in Table 21 show the direction of change in the set WACC compared to the previous period (ie whether it increased or decreased or remained broadly equal). As can be seen from the tables, **there is considerable variability in the allowed or target cost of capital across the Member States**. To facilitate comparisons, we also present the same information for the two most common approaches (pre-tax nominal and pre-tax real) graphically, in Figure 49 and Figure 50. Moreover, to obtain further insights into the causes of the variations, sub-sections 13.4 to 13.6 present data on the various parameters underpinning the WACC calculations.

Table 21 WACC values by country and basis (most recent regulatory period)

Country	Pre-tax nominal	Pre-tax real	Vanilla real	Vanilla nominal	Post-tax nominal
Austria					
Belgium	3.74%v				
Bulgaria	8.14%^				
Czech Republic	7.94%^				
Germany					
Denmark					
Estonia				5.63%n/a	
Greece	9.22%v				
Spain	5.09%+'RCS'[51]v				
Finland	7.38%=				
France		5.25%v			
Croatia	5.22%v				
Hungary		4.62%v			
Ireland		4.63%v			
Italy		5.40%=			
Lithuania	5.80%v				
Luxembourg	6.12%v				
Latvia					4.68%v
Netherlands[52]		3.00%/3.6%/4.3%[53]			
Poland	6.19%^				
Portugal[54]	6.04%v				
Romania					9.41%v

[51] According to the Spanish NRA (CNMC), a WACC is not explicitly set, rather financial compensation is provided based on the price of money in Spain for 10 years plus 0.5% and the RCS is an amount of money that is included in allowed revenues serving to 'improve' the WACC (like a WACC premium).

[52] The WACC varies by year and type of investment. The CoE is uniform throughout, but the RFR and CoD vary depending on the year and whether capex is for replacement/refurbishment or expansion (as it takes into account embedded debt costs, if relevant). Eg, the WACC for replacement/refurbishment investments (real, pre-tax) is set at 4.3% in 2016 and 3.0% in 2021. For expansion investments, it is set at 3.6% in 2016 and 3.0% in 2021.

[53] The NRA's decision is the subject of an appeal, so these values might change.

[54] This is the average for the regulatory period.

Country	Pre-tax nominal	Pre-tax real	Vanilla real	Vanilla nominal	Post-tax nominal
Sweden		6.91%[n/a]			
Slovenia	6.98%[n/a]				
Slovakia					
Great Britain			4.38%[v]		
Northern Ireland			2.11%[^]		

Table 22 WACC values by country and basis (previous regulatory period)

Country	Pre-tax nominal	Pre-tax real	Vanilla real	Vanilla nominal	Post-tax nominal
Austria					
Belgium	6.55%				
Bulgaria	6.29%				
Czech Republic	6.105%				
Germany					
Denmark					
Estonia				n/a	
Greece	10.99%				
Spain	7.80% to 9.67%[55]				
Finland	7.39%				
France		6.50%			
Croatia	5.76%				
Hungary		8.78%			
Ireland		5.2% to 8.2%[56]			
Italy		5.40%			
Lithuania	5.00%				
Luxembourg	7.60%				
Latvia				8.00%	
Netherlands		3.60%			
Poland	5.64%				
Portugal[57]	7.55 %				
Romania					10.40%
Sweden		n/a			

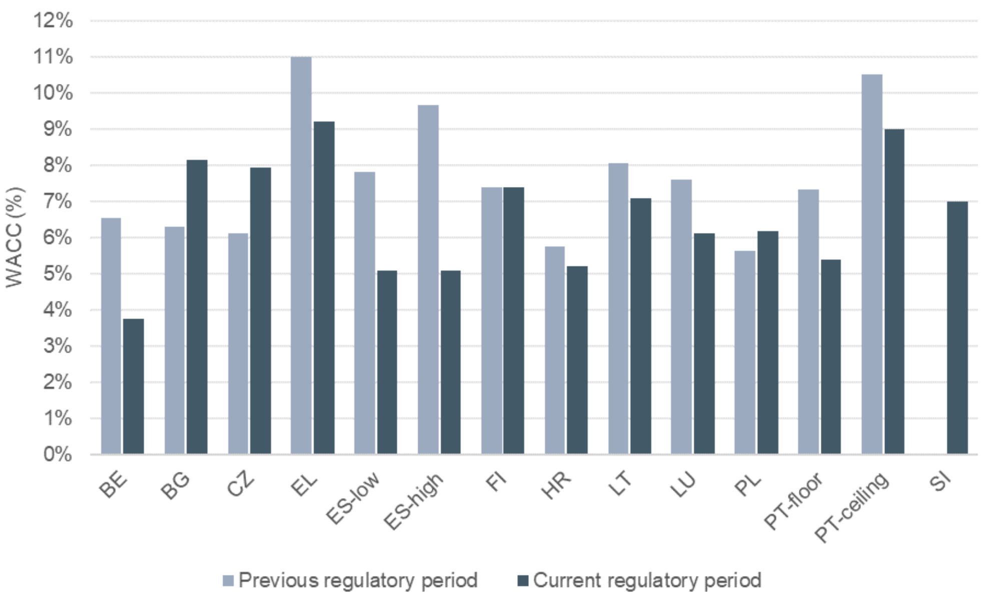
[55] The WACC was reset every year given the financial instability at the time.

[56] The NRA (CRU) included a trigger mechanism in the WACC whereby the allowed cost of capital was reviewed annually and adjusted if there were further significant changes in market conditions in Ireland. The range presents the floor and ceiling set for the allowed WACC.

[57] Due to the uncertain and financially unstable environment since 2011, the rate of return in Portugal is updated *ex-post* (each 'gas' year). The WACC, applied since July 2013, is indexed to the Portuguese 10-year bond benchmark and depends, in each year, on its evolution, with a cap and a floor. The rate shown in the table is the average for the regulatory period.

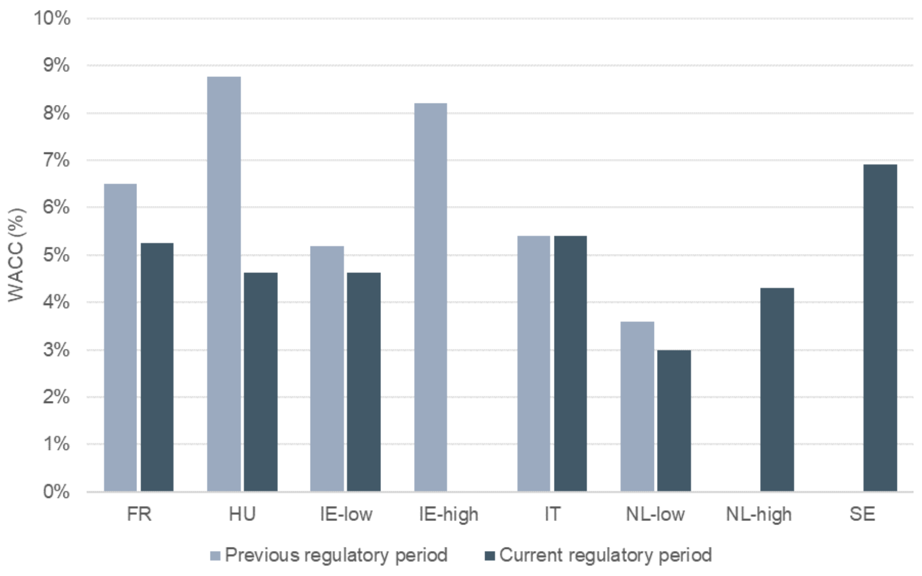
Country	Pre-tax nominal	Pre-tax real	Vanilla real	Vanilla nominal	Post-tax nominal
Slovenia	n/a				
Slovakia					
Great Britain			5.05%		
Northern Ireland			1.98%		

Figure 49 Comparison of pre-tax nominal WACCs



Source: NRAs, ECA analysis

Figure 50 Comparison of pre-tax real WACCs[58]



58 Netherlands is not shown in the graph because of the varying WACCs applying gin the current period depending on the year and type of investment. As stated earlier, the current WACC range is 3.0% to 4.3% and in the previous period it was 3.6%.

Source: NRAs, ECA analysis

13.3 WACC premiums

To ensure that comparisons of allowed returns are on a broadly comparable basis, NRAs were also requested to indicate whether they allow premiums to the 'normal' WACC and under what circumstances. In response, **seven NRAs indicated that they employ WACC premiums** as follows[59]:

- **Austria allowed a 3.5% premium in its most recent decision on the equity-financed component of RAB for 'volume risk'** – 3.5% was applied to the 'volume risk' of equity-financed assets (volume risk was incorporated with the introduction of entry/exit tariffs). Tariffs were set based on an assumed level of contracted capacity and there is then an asymmetric adjustment for realised volumes. Specifically, if volumes exceed the assumed capacity level, tariffs are adjusted (decreased) for actual volumes (so the regime operates as if it is a revenue cap), but if realised volumes are below the initially fixed capacity level, there is no corresponding adjustment (which would entail unit tariffs increasing) and therefore the TSO bears the volume risk (the regime operates like a price cap). This volume risk is calculated and the premium intends to compensate the TSO for the risk.

- **Belgium applies a 1.25% WACC premium** to those investments deemed necessary for ensuring **security of supply**.

- **Finland** applies an unspecified risk premium **for availability risk** (associated with sourcing gas from a single foreign supplier) **and demand risk** (given that according to the NRA there is a significant number of gas users that can substitute gas with other fuels).

- **France applies a WACC premium on an *ad hoc* basis depending on the importance of the investments**. In the current period there is no premium applying, but France did apply a **3% premium in the previous regulatory period for investments in interconnectors and the merging of market zones** (which facilitate market integration and competition).

- **Italy applies a time-limited (7-12 years) WACC premium (1%-2%) to investments that expand transmission capacity**. The premium applied has varied over time and depending on the nature of the capacity expansion:

  - For investments commissioned in the 2014-2017 period, the following premiums apply

    - 1% for seven years for investments increasing *regional* network transmission capacity

[59] We note that in addition to the NRAs below, the possibility of applying a WACC premium is also foreseen by the tariff regulation in Greece, but none has been applied by RAE (the NRA) in practice.

    - 1% for 10 years for investments increasing *national*[60] network transmission capacity

    - 2% for 10 years for investments that both increase *national* network capacity and facilitate gas imports or exports

  - For investments commissioned in 2018 and 2019, a 1% premium applies for 12 years for investments increasing network transmission capacity

- **Latvia generically applies a 2.13% WACC premium** (above that reported in the previous section) **for** regulated businesses of **the gas sector**

- **Romania applies a WACC premium of 1.4% for different categories of investment**, primarily for new **interconnectors** and **innovations** that improve the operational efficiency of the gas transmission system

- **Sweden applies a premium of 1.5%** (which appears to apply to all investments).

13.4 The cost of equity

13.4.1 Total market returns or MRP emphasis?

In section 6.2.2, we discussed the alternative approaches to calculating the market risk premium (MRP) component of the cost of equity, namely:

- By assuming that total market returns (TMR) are broadly constant and that MRP is inversely correlated with the RFR ('TMR emphasis'), or

- By assuming that the MRP is largely constant and so TMR is positively correlated with the RFR, and MRP is then directly estimated ('MRP emphasis').

After exploring this issue with the NRAs, it is clear that **the more conventional approach is to assume a broadly constant or calculated MRP that is added to a varying RFR** (although in many cases this did not appear to be an issue that was given special consideration and therefore the approach was adopted effectively by default).

A total returns approach is adopted only by four NRAs – those on the British Isles ie in Ireland, Great Britain and Northern Ireland, and in Italy.

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[60] In Italy, there is a distinction made between the national transmission system and regional transmission pipelines. The distinction depends on the purpose of the pipeline and the degree to which the relevant network meets a predefined set of criteria established by the Government (relevant Ministry). Generally, the national system comprises the large diameter pipes that transport gas from the entry points of the system (import gas pipelines, LNG regasification plants and the major domestic production centres) to regional transmission network interconnection points (and to gas storage facilities), where the gas is transported to a more localised set of industrial users, power stations and urban distribution networks.

13.4.2 Arithmetic or geometric averages?

Regarding the use of arithmetic versus geometric averages for setting the MRP, **most NRAs rely on arithmetic averages**. The only **exceptions** are the following **six NRAs**:

- Ireland, Italy and Portugal, which use geometric averages
- Belgium, Germany and Netherlands that apply the average (arithmetic mean) of the arithmetic and geometric means.

13.4.3 The risk-free rate

Figure 51 below shows the risk-free rates used by the NRAs for setting the WACC in the two most recent regulatory decisions (wherever relevant). The RFRs reported are those which are used for setting the cost of equity, although as far as we could ascertain the same rate is used in almost all cases for the cost of debt, where the latter is set by applying a debt premium to the RFR.

We note that caution needs to be exercised in comparing the rates below as they are not on an equal basis – some are nominal and some are real (the latter countries are shown with an asterisk in the graph), while some also include a country risk premium (CRP) while others either do not have such a premium or add this separately or to the MRP. Even with these caveats, it is clear that **there is large variability between the RFRs used, and these to a large degree explain the variance in the adopted WACC values** (given that there is less variability in the MRP as discussed in the next sub-Section, and to a lesser degree in the equity betas presented in Section 13.4.5).

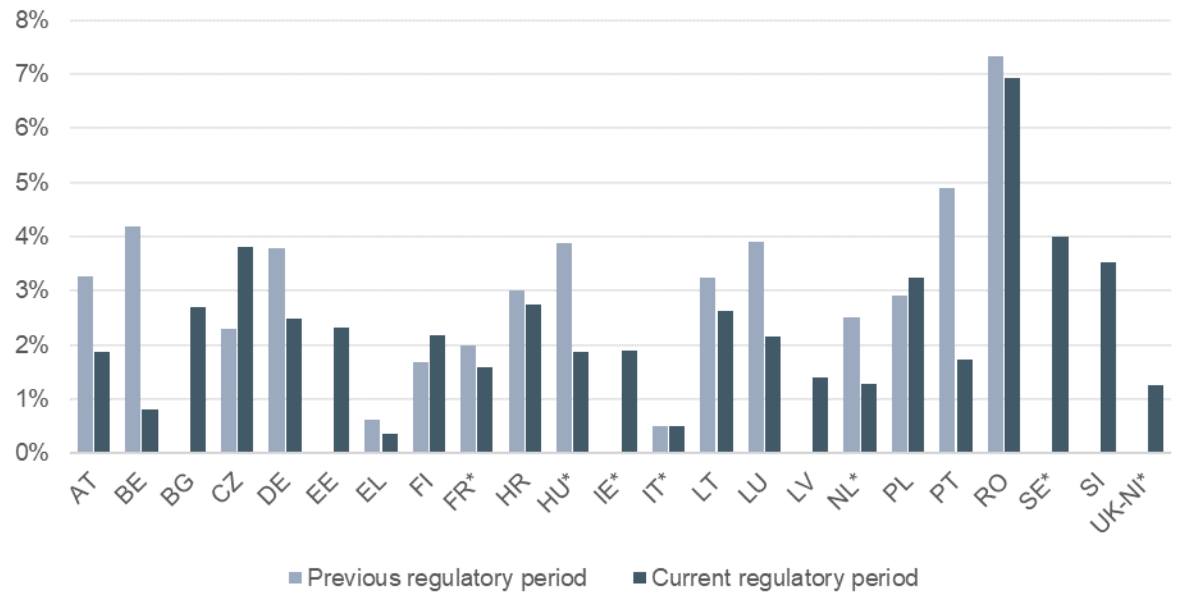
The variability in the adopted RFRs is due to the different reference or regulatory periods used, but also (and mostly) because of the different bases employed for calculating the RFR:

- **Most countries set the RFR by reference to their own government bonds**, so the RFRs will necessarily reflect the variability between different government bond yields – this applies to Austria, Belgium, Bulgaria, the Czech Republic, Germany, Finland, France, Croatia, Luxembourg, Latvia, Poland, Romania, Sweden, UK-GB (although checked against other country RFRs) and UK-NI
- **Several countries set the RFR according to yields on highly graded Eurozone bonds**:
  - Austria and Portugal use only AAA-rated countries
  - Italy uses AA-rated
  - Estonia, Greece and Slovenia use German bonds alone
  - The Netherlands employs a 50/50 weighting of Dutch and German bonds
  - Lithuania uses a weighting of its own and Eurozone bonds[61]

[61] Ireland also uses Eurozone bonds, but did not state which ones exactly.

- Hungary sets its RFR **by reference to US rates** to which a CRP is added.

Figure 51 Risk-free rates by country (last two regulatory decisions)



Note: Countries with an asterisk have real rates; all others are nominal. Some countries (eg Greece and Hungary) add a country-risk premium (CRP) on top of the RFR, while others (eg Romania) incorporate it in the RFR. In the case of Portugal, a combination of the two approaches was used across the two most recent regulatory periods – in the previous period the CRP was added to the RFR, but in the current period it has been added to the MRP.
Source: NRAs, ECA analysis

13.4.4 The market risk premium

The market risk premiums (MRPs) adopted by the NRAs show **more consistency between regulatory periods and across countries** – see Figure 52 below. Looking at the most recent regulatory periods, the majority of the countries (almost half) used an MRP in the 4.5%-5.0% range. More specifically (and excluding Denmark, Spain, Slovakia and UK-GB where the issue of an MRP is irrelevant or was not stated):

- There are **13 countries currently employing an MRP between 4.5% and 5.05%** - Austria, the Czech Republic, Estonia, Finland, France, Croatia, Ireland, Lithuania, Luxembourg, Latvia, the Netherlands, Poland and Sweden

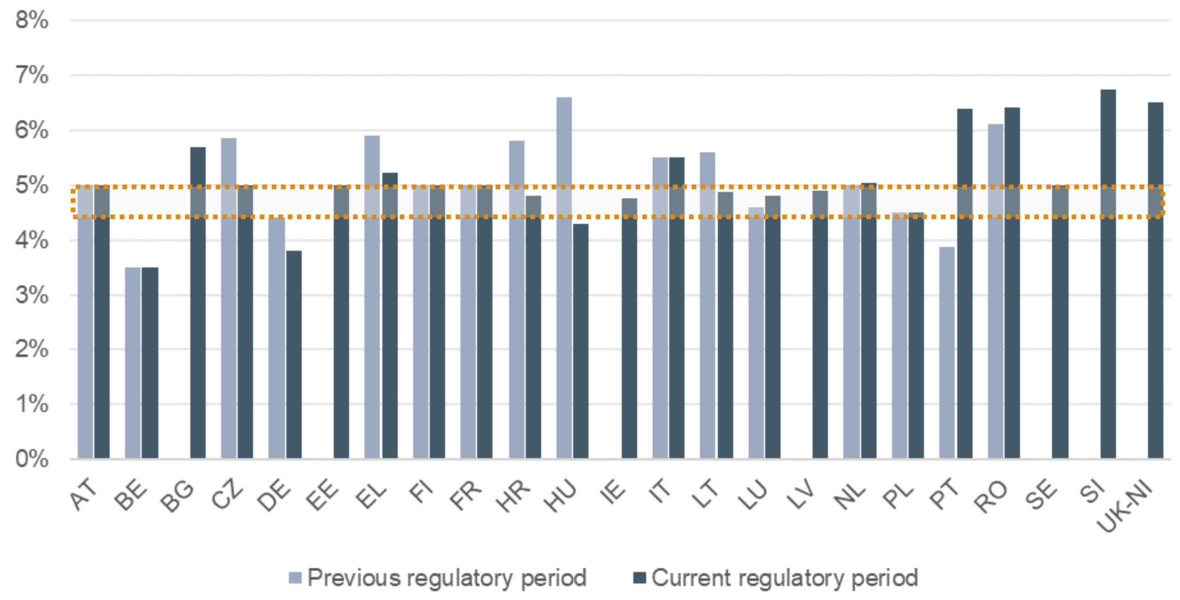
- **Three countries have set an MRP below 4.5%** - Belgium (3.5%), Germany (3.8%) and Hungary (4.3%)

- **Three countries have an MRP between 5% and 6%** - Bulgaria (5.69%), Greece (5.23%) and Italy (5.5%)

- **Four countries have employed an MRP greater than 6%** - Portugal (6.38%, which is inclusive of a country risk premium), Romania (6.42%), Slovenia (6.75%) and UK-NI (6.5%).

We attribute the broader consistency in the MRPs to the fact that most NRAs use very long-term data (in many cases dating from the early 1900s) to estimate the premium, which tends to remove the effects of shorter term fluctuations in equity markets.

Figure 52 Market-risk premiums by country (last two regulatory decisions)



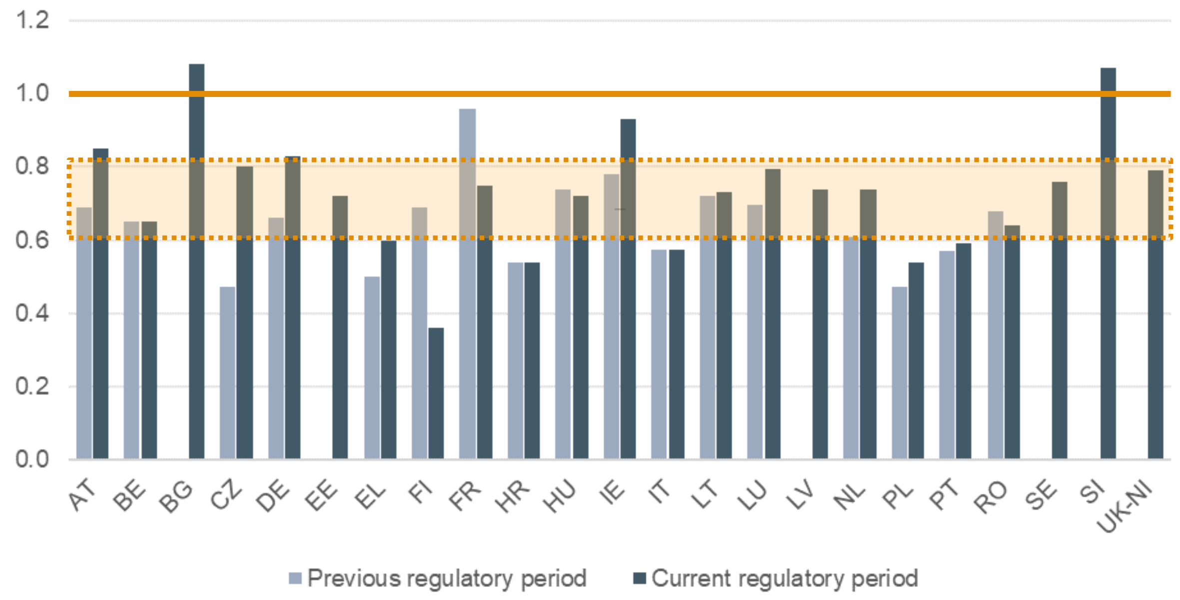
Note: The MRPs for Portugal are not comparable as the rate for the previous period excludes the CRP, whereas it has been included in the MRP for the current period. Also, the MRPs shown are the averages used within the pre-specified floors and caps.
Source: NRAs, ECA analysis

13.4.5 The equity beta

In the figure below, we show the equity betas that were adopted by the NRAs in the two most recent regulatory periods (wherever available). We note again that the higher the beta, the higher will be the cost of equity and/or WACC applied (given that the beta is multiplied by the MRP and added to the RFR to derive the cost of equity).

As shown in Figure 53, **the vast majority of NRAs apply an equity beta below 'one'** (the solid line in the graph below), indicating that NRAs consider regulated TSOs to be less risky than the market as a whole. The only exceptions (ie those Member States with an equity beta higher than 'one') are Bulgaria (1.08) and Slovenia (1.07), which on first viewing seems incongruous given that the former states that it relies on precedents adopted elsewhere, while the latter calculates beta based on a broad group of EU companies (and therefore mostly uses a similar sample to many other NRAs). Moreover, both NRAs apply revenue caps, which arguably removes a large element of systematic risk (ie volume/demand volatility).

Figure 53 Equity beta by country (last two regulatory decisions)



Source: NRAs, ECA analysis

Of the remaining countries where an equity beta is set or has been stated (so this again excludes Denmark, Spain, Slovakia and UK-GB), we note the following:

- **Most (13) NRAs have adopted an equity beta between 0.6 and 0.8** (as highlighted by the coloured box in the figure) - this is true of Belgium, the Czech Republic, Estonia, Greece, France, Hungary, Lithuania, Luxembourg, Latvia, the Netherlands, Romania, Sweden and UK-NI

- **Three NRAs employ a beta between 0.8 and 1.0**, namely, Austria (0.85), Germany (0.83) and Ireland (0.93), although all three had lower betas and in the 0.6-0.8 range in the previous regulatory period

- **Five NRAs use an equity beta below 0.6** – Finland (0.36), Croatia (0.54), Italy (0.575), Poland (0.5389) and Portugal (0.59).

13.4.6 The allowed or target cost of equity

The resulting cost of equity for each country derives from the parameters already presented ie the RFR, the MRP, CRP (where relevant) and the equity beta. We do not present the resulting figures here, as the cost of equity is further complicated by whether it is expressed in after or pre-tax terms with the corporate tax rates applying in each country being highly variable (as well as whether it is in real or nominal terms), and therefore this makes direct comparisons difficult and potentially misleading.

13.5 The cost of debt

13.5.1 The method of setting the cost of debt

Turning to the cost of debt component of financing costs, most NRAs set the cost of debt on an *ex ante* basis (ie without subsequent correction for realised debt costs). In particular:

- **23 NRAs set debt costs this way (ie *ex ante*)** – Austria, Bulgaria, the Czech Republic, Germany, Estonia, Greece, Finland, France, Croatia, Hungary, Ireland, Italy, Lithuania, Luxembourg, Latvia, the Netherlands, Poland, Portugal, Romania, Sweden, Slovenia, Slovakia and UK-NI
- **Two NRAs set the cost of debt *ex post*** – Belgium and Denmark
- **Two NRAs employ some other mechanism** – Spain, where there is no WACC applied but a financing rate (covering the cost of debt and equity), and UK-GB, which sets debt costs based on a trailing index of corporate bonds (the 'iBoxx non-financials index' for A and BBB credit ratings), although this is also applied on an *ex ante* basis.

Of the 24 NRAs setting the cost of debt *ex ante* (including UK-GB):

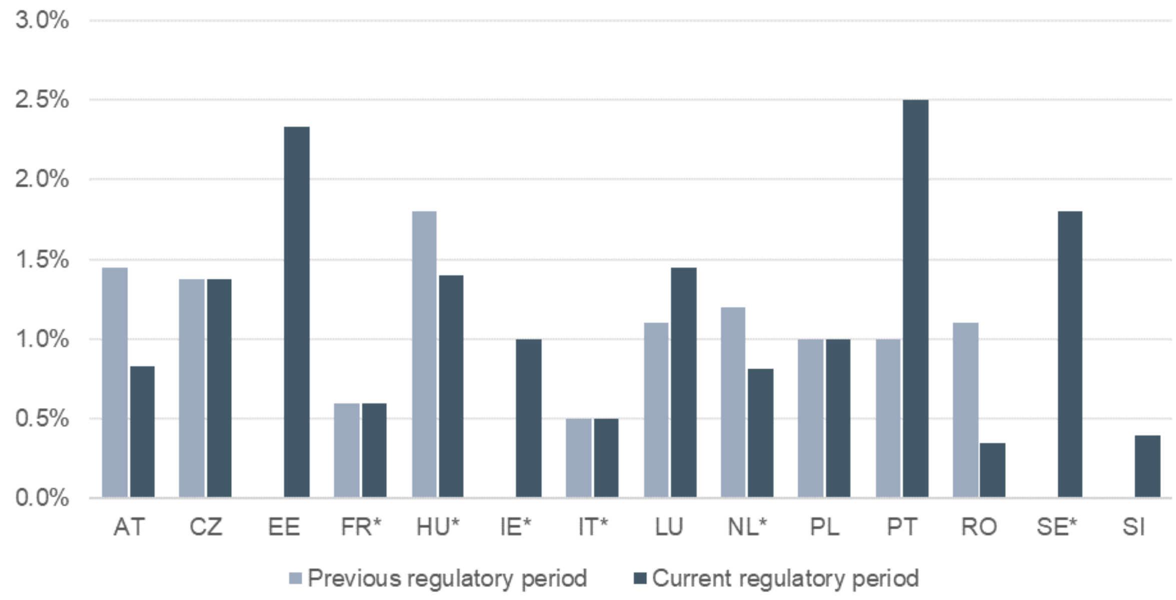
- **16 NRAs use an RFR plus debt premium approach** – Austria, the Czech Republic, Estonia, Finland, France, Hungary, Ireland, Italy, Luxembourg, the Netherlands, Poland, Portugal, Romania, Sweden, Slovenia and Slovakia
- **Eight NRAs set debt costs based on observed yields** (although different proxies are applied for the market cost of debt) – Bulgaria, Germany, Greece, Croatia, Lithuania, Latvia, UK-GB and UK-NI.

13.5.2 Debt premiums

In this sub-Section, we show the debt premia applied in those countries where this approach to setting the cost of debt is used. The premia applied in the two most recent regulatory periods are presented in Figure 54. As before, caution should be exercised in comparing these, as some are expressed in real terms (for countries indicated by an asterisk) and others in nominal terms. Nevertheless, it is clear that there is significant variability in the debt premia applied (which is largely due to the differences in the estimation methods or calculations used – the reference periods, the choice of comparators, the corporate bond maturities, etc). As demonstrated in the figure (and focusing on the most recent regulatory period):

- **Most countries (six) apply a debt premium of between 1.0% and 1.5%**
- **Four countries use a debt premium of 0.5%-1.0%**
- **Three countries have debt premia above 1.5% and two countries have premia below 0.5%.**

Figure 54 Debt premia applied by country, where relevant



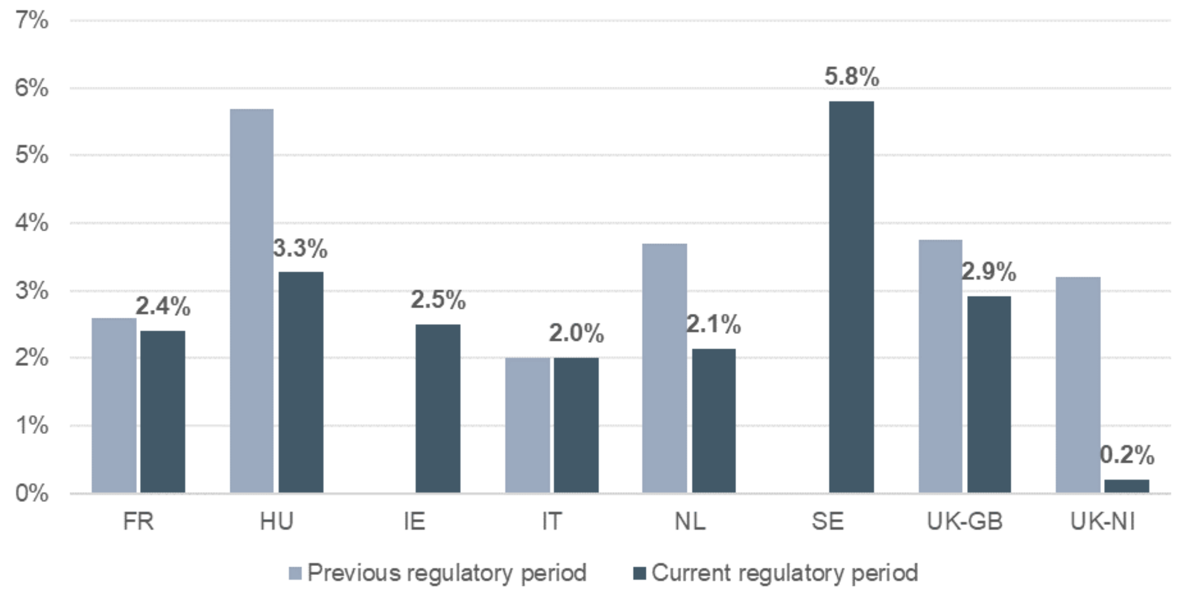
Note: Countries with an asterisk have real rates; all others are nominal
Source: NRAs, ECA analysis

13.5.3 The allowed or target cost of debt

The following two figures show the resulting cost of debt adopted for both real and nominal regimes, respectively. Some observations based on these are the following:

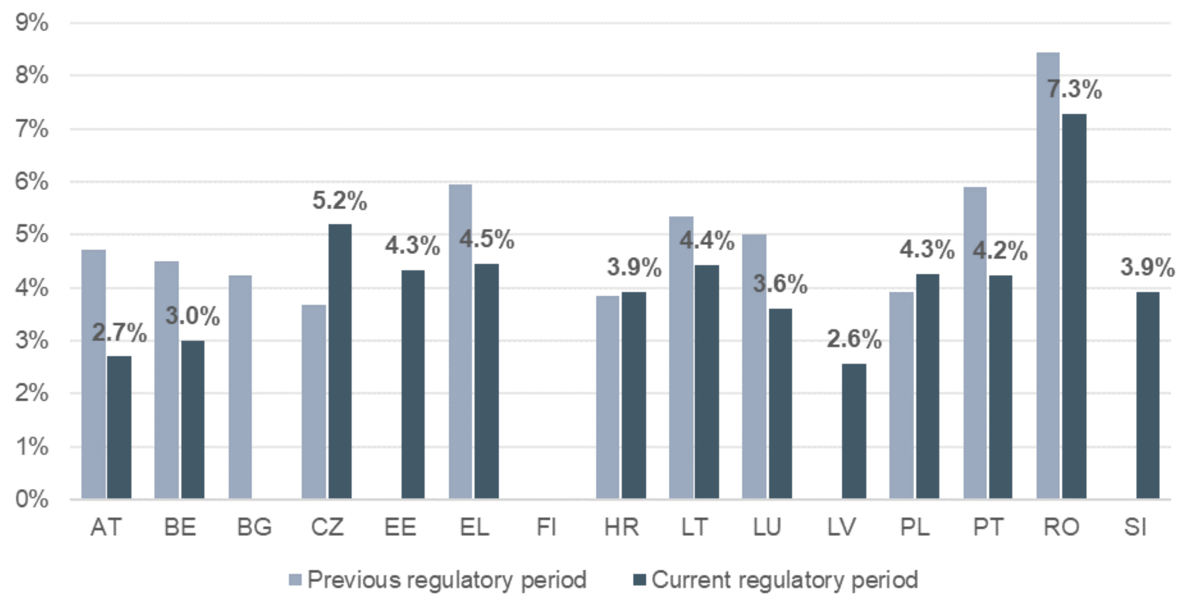
- **Allowed debt costs have mostly (although not universally) fallen between the previous and current regulatory periods**
- In those countries applying **real rates**, there is broad comparability of debt costs, with **most falling in the 2%-3% range**, with the outliers being, at the upper end, Sweden (5.8%) and, at the lower end, UK-NI (0.2%)
- In those countries with **nominal regimes, debt costs are generally in the 3%-4.5% range**, except for Austria and Latvia which are a little below the lower end of the range and the Czech Republic which is a little above the upper end, while Romania appears to be the outlier with an allowed cost of debt of 7.3%.

Figure 55 Cost of debt (real) by country (last two regulatory decisions)



Source: NRAs, ECA analysis

Figure 56 Cost of debt (nominal) by country (last two regulatory decisions)



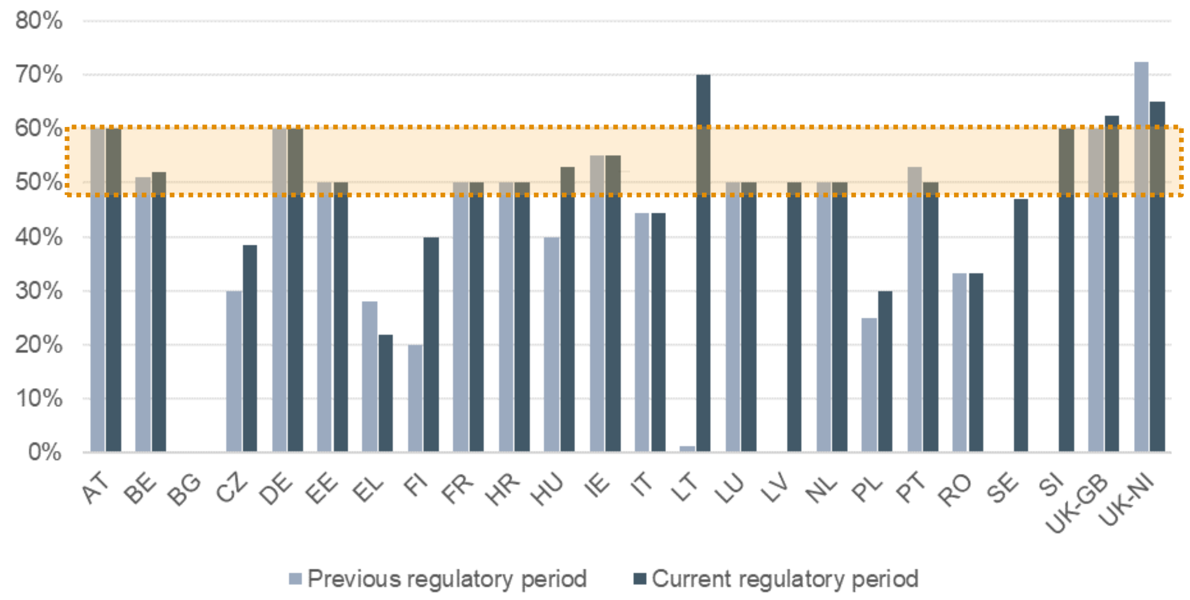
Source: NRAs, ECA analysis

13.6 Gearing

The final element of the WACC calculation we consider is the gearing approach and level employed by the NRAs. Of those that use the WACC concept (and therefore need to apply weights to the equity and debt components), **22 use notional gearing and only two NRAs use actual gearing** (Bulgaria and Greece). The gearing levels employed are shown in Figure 57 below. As demonstrated in the graph:

- **Most NRAs, 13 in total, apply a gearing level of 50%-60%** - Austria, Belgium, Germany, Estonia, France, Croatia, Hungary, Ireland, Luxembourg, Latvia, the Netherlands, Portugal and Slovenia
- **Three NRAs respectively use gearing levels in each of the following ranges**:
  - **61%-70%**, namely, Lithuania, UK-GB and UK-NI
  - **40%-50%**, these being Finland, Italy and Sweden
  - **less than 40%** - Bulgaria, the Czech Republic and Greece.

Figure 57 Gearing level by country (last two regulatory decisions)



Source: NRAs, ECA analysis

13.7 Financeability

Financeability assessments are not widely undertaken in the EU. These are limited to just the three NRAs of the British Isles (ie Ireland, UK-GN and UK-NI) and Lithuania. This is somewhat surprising given the prevalence (as discussed in Section 12.3) of rolling investments into the RAB only once the assets have been commissioned (and therefore the absence in these cases of pre-financing for the relevant capital expenditure programmes).

14 Other regulatory mechanisms

In this final Section reviewing EU practices, we examine other incentive and adjustment mechanisms that might be employed by the NRAs, namely:

- The treatment of revenue over and under-recoveries
- The treatment of underspends and overspends against cost allowances (where relevant)
- The degree to which rewards and penalties apply to meeting quality and other performance measures.

14.1 Over or under-recoveries of revenue

The questionnaire issued to the NRAs requested that they indicate whether revenues and tariffs are adjusted for over and under-recoveries within the regulatory period (eg annually) or between regulatory periods (cumulatively). The responses indicated that:

- **Eight NRAs adjust revenues between regulatory periods**
- **Seven NRAs adjust revenues within regulatory periods**
- **Seven NRAs stated that they do both** – we interpret this as meaning that revenues are adjusted annually, but shortfalls or over-recoveries in the final year of the regulatory period naturally carry over to the next period.

The NRAs employ many different approaches regarding the mechanics of the adjustments, regarding, for example:

- the time over which they are spread (eg this was sometimes dependent on the level of adjustment, with higher adjustments being spread over more years)
- whether penalties are applied (as an incentive to ensure accurate forecasting and individual tariff setting by the TSOs)
- whether adjustments are made for all revenue variations or only if they are material (and exceed certain bands)
- whether the treatment is symmetrical (between shortfalls and over-recoveries).

The NRAs also display much variability in the rate used for the time value of money when making the adjustments. By way of example (and without necessarily covering all NRAs):

- Several use a short-term borrowing rate, whether this is by reference to a particular published rate or an administratively specified (and relatively low) interest rate

- The most popular approach (although still among a minority of NRAs) was to apply a price index, in most cases CPI
- The weighted average cost of capital was used only by two NRAs, and in one case a percentage point penalty on the WACC is applied if over-recoveries are 'large'
- A couple of NRAs use the allowed cost of debt, while two others employ the risk-free rate (although for one NRA, this forms the base to which an unspecified premium is added).

14.2 Treatment of underspends and overspends

As discussed in Section 7 of this Report, incentive-based regimes sometimes foresee, after having set the baseline revenue requirement, adjustments to revenues to account for outturn costs and activities (ie on an *ex post* basis). This is typically done to retain constant incentives for TSOs to pursue efficiencies and to share the benefits of cost savings (or the burden of cost overruns) with network users. Having explored this issue with the NRAs, we found that there is fairly limited use of such adjustment mechanisms, currently. More specifically:

- **For opex**:
  - **Six NRAs use efficiency sharing mechanisms** (where, typically, a sharing rate in per cent is applied to the over/under spend accumulated during a regulatory period). These mechanisms are used in Belgium, Croatia, Italy, Latvia, Portugal and UK-GB. The sharing ratio is generally 50%, although in UK-GB it was 44.36% (applied to TOTEX) in the last regulatory decision.
  - **One NRA uses a rolling mechanism** (where a TSO retains/incurs the benefits/costs of an underspend/overspend for some specified time). This is the case for Romania where the 'retention' period is five years (which is equal to the length of the regulatory period).
  - **One NRA uses a different mechanism** – this is Hungary, which employs a profit-sharing mechanism irrespective of the cause of over-recovery (so also applies to capital expenditure discussed below). The approach used can be characterised as 'asymmetrical earnings sharing', that is, if the TSO earns profits above those allowed, then 50% of the difference 'may' be shared with network users, but there is no adjustment for lower profits than those allowed. Although the mechanism does not necessarily apply automatically, the NRA has always made adjustments in practice[62].
- **For capital expenditure**, there is even more restricted use:
  - **Three NRAs use sharing mechanisms** – Spain, where assets are rolled into the RAB based on the average of actual cost and 'reference unit costs' used for setting allowed revenues, Luxembourg, where a 30/70 (TSO/network

[62] Northern Ireland also applies adjustment mechanisms for both operating and capital expenditure, but the nature of the regime was not specified.

users) symmetrical sharing mechanism applies, and UK-GB as mentioned above.

14.3 Performance metrics and rewards/penalties

Finally, another area explored with the NRAs, which in principle is important for incentive-based regimes, is the extent to which there are additional 'revenues at risk' (ie further rewards or penalties) associated with a performance regime that sets quality and performance targets and standards.

The results of the survey show that there is limited use of performance regimes or other similar incentive mechanisms, with only the following **four NRAs specifying that such incentives are used**:

- **Austria** - TSOs are measured on the following performance metrics (with weighting in brackets): customer satisfaction (25%), unplanned availability time (25%), transparency obligations and quality of data (25%), environmental aspects (15%), and agency cooperation (10%). This is a reward-only incentive regime, with up to 5% of opex (excluding the cost of fuel gas) 'at risk'.

- **Finland** – rewards are paid when energy not supplied (ENS) is in the top quartile when compared to the reference years (2008-2015). Penalties apply when ENS is in the bottom quartile, and there is a deadband in the middle. The scheme applies symmetrically: +/-2% of 'reasonable return' for the year.

- **France** – there is a quality of supply regime entailing 16 different metrics and other schemes, including additional rewards for implementing large investment projects (>€20m) significantly below budgeted costs (and corresponding penalties for significant cost overruns), and an R&D funding scheme.

- **UK-GB** – there are various schemes in place that cover financial, statutory and reputational incentives.

15 Evaluation of EU methodological practices

In this final Section of the Report we provide a broad evaluation of the key elements of the revenue setting methodologies adopted by the EU NRAs and which were summarised and discussed in the preceding Sections 10 to 14. For this purpose, we apply the assessment framework we outlined in Section 8.3 of the Report. This is summarised in Figure 58 below. To recap, we:

- focus on **five key aspects of the regulatory approaches** – the overall framework (or, more precisely, the form of revenue control), the setting of expenditures, the asset base, the cost of capital, and other (adjustment and incentive) mechanisms
- apply **three broad assessment criteria**, covering economic ***efficiency*** (productive, allocative and dynamic), ***risk allocation*** (for volume and costs) and other general ***regulatory and/or consumer objectives*** (such as transparency, simplicity, predictability and regulatory gaming)
- attempt to draw some useful **observations and conclusions** regarding the possible further development of the regulatory frameworks.

Figure 58 Methodology assessment framework

Source: ECA

The rest of this Section is structured around the five respective regulatory elements forming the focus of the assessment. Depending on the framework element, we also **focus only on specific aspects of the three broad assessment criteria, as some are more relevant than others and do not always carry the same weight**. We also emphasise that the assessment draws out relative strengths and weaknesses and should not be interpreted as a scoring mechanism with unambiguously better approaches. Finally, the assessment and discussion is relatively (and necessarily) high-level, as the detailed consideration of each of these regulatory elements would constitute a separate study in itself, which is beyond the scope of the present assignment and Report.

15.1 Overall regulatory framework

In this sub-Section we focus on the **revenue control mechanism** employed by the various NRAs. As discussed in section 10.1, the most common method currently employed by EU NRAs is a revenue cap. This is followed by hybrid regimes that employ cost-plus for capital expenditure and a revenue or price cap (or combination of the two) for operating expenditure. Pure price cap and cost-plus regimes are much less prevalent, while a few

NRAs apply other frameworks that cannot be readily captured under the abovementioned models.

The discussion below focuses on price and revenue caps, and cost-plus regulation, as hybrids will display elements of these regimes depending on the actual design and mix of approaches employed.

15.1.1 Economic efficiency

Productive efficiency

Revenue cap regimes should generally provide strong incentives for operating cost reductions and maximising efficiency gains, given that (subject to any sharing mechanisms) revenues are fixed and therefore the higher the reduction in costs, the higher are the profits of the regulated company. This is generally the case for any of the incentive-based regimes (so **would apply to the price caps and to a lesser degree to the hybrid systems**), and **contrasts the cost-plus regimes where efficiency incentives are muted** given that any cost reductions are passed through to customers and therefore do not improve company profitability.

Also, **a revenue cap** 'guarantees' the TSOs a particular level of revenue, irrespective of demand fluctuations (which is the main transmission mechanism of systematic risk). This should therefore **lower the cost of capital** to the regulated TSO, **relative to a price cap (although it would still be higher relative to a cost-plus or rate of return regime**). However, it is unclear whether the theoretical advantage of revenue cap regimes has translated in practice to a lower cost of capital – for example, we did not find that the reported asset or equity betas for revenue capped TSOs are systematically and materially different from those under hybrid systems or price caps. We believe the lack of such a link may be attributed to:

- a seemingly general absence of a systematic assessment by NRAs of the cash flow risks faced by TSOs
- other features of the regulatory environment that might increase the volatility of TSO cash flows (such as *ad hoc* expenditure reviews, unclear cost assessment frameworks and therefore the risk of arbitrary or inconsistent decisions, etc)
- the use of a common pool of listed firms (given the limited number of pure regulated TSOs listed on EU stock exchanges) for calculating beta.

Dynamic efficiency

Whether the above efficiency incentives apply to **investments and innovations over time** is even more **contentious**. In the case of revenue-cap regimes, there is arguably an incentive to delay investments (within a regulatory period and perhaps even between periods), especially those associated with quality improvements or service expansions – this is because revenue remains the same irrespective of demand, so the latter does not determine total revenue and profits.

In the case of price caps, investment and innovation incentives might also be lower if these lead to reductions in throughput (and therefore future revenues/profits). Cost-plus regimes, as discussed in Part I of this Report, might result in the opposite problem, that is, of 'gold-plated' investments.

Where expanded service coverage is important, therefore, revenue caps might not be the preferred option and cost-plus or rate of return regimes might be favoured instead (this might partly explain for example the use of cost-plus in Greece, where the gas system is still relatively new). **Price caps may also be preferred as these provide incentives for TSOs to meet and expand demand** since the marginal revenue received when demand increases is not constrained, as it would be under a revenue cap regime. Hence, provided the marginal cost of supply is lower than the marginal revenue associated with the expanded service coverage, TSOs will have the incentive to meet demand. This could be the case for example in Estonia, which is the only country with a price cap and which is typically characterised by low utilisation rates (~10%) and therefore excess capacity.

Allocative efficiency

Tariff design

Allocative efficiency in the present context is closely tied with the **incentive** provided by the revenue setting methodology **to set efficient tariffs (or tariff structures)**. Given that under revenue caps, TSOs cannot earn extra revenue by adjusting tariffs, these regimes have generally been considered as not providing strong incentives for setting cost-reflective or efficient tariffs and have been associated with passive pricing strategies.

By contrast, other incentive-based regimes (such as price caps and to a lesser degree hybrids) that do not set a limit on earnings, theoretically allow TSOs to readjust tariffs to increase their revenues. For example, such tariff rebalancing might entail increasing tariffs or tariff components that are more demand inelastic, or raising tariffs in congested parts of the network to avoid the cost of system expansion. Adjusting tariffs in these ways (which involves what economists term 'Ramsey Pricing') is generally considered an efficient way of recovering transmission network costs (although these prices are sometimes criticised for their equity implications).

Nevertheless, there is limited evidence that in practice such tariff readjustments are actively pursued by companies regulated under price caps (or similar regimes, such as weighted average prices, hybrids, etc), or that any tariff rebalancing that is undertaken is necessarily consistent with efficient pricing principles (ie that tariffs are compatible with short-term and/or long-term marginal transmission network costs). For this reason**, tariff design and structures are sometimes regulated directly, which is the case now with the EU Gas Network Tariff Code** (and which predominantly covers tariff structure issues and methodologies). Indeed, given the importance of demand forecasts for the development of the entry-exit tariffs under the Code, a revenue cap regime may be preferable - there is generally no incentive (other things equal) for biasing the demand forecast under revenue caps[63], as there is for example under a price cap where a TSO might push for a lower demand estimate, which would result in a higher overall price cap.

Demand management

A well-known aspect of **price cap regimes**, particularly where cost structures are heavily biased towards fixed costs (as they are in gas transmission), is to **create strong incentives to maximise throughput as this increases revenues and profitability** (or at least, they do not provide incentives to reduce demand, as this would result in lower revenues). Again, this is not true of **revenue caps**, which **are** therefore **more conducive to implementing demand management programmes** and/or to curtailing the need for system augmentations. Hence, revenue caps are generally considered to be more compatible with demand management objectives, where these are important. Conversely, a price cap may be appropriate if there is long term excess transmission capacity. Cost-plus arrangements on the other hand, do not provide incentives either way (unless the cost of capital is set artificially high, which would provide a bias towards undertaking network investments, but this would be the case under incentive regulation too).

15.1.2 Risk allocation

Volume risk

A revenue cap means that revenues are fixed regardless of outturn demand, so that average tariffs increase (decrease) as average demand falls (rises) thereby keeping revenues stable. Hence, the risk of higher or lower tariffs due to demand differing from forecast is borne by network users. Conversely, under a price cap, TSO revenues fluctuate based on actual demand, so that the revenue risk resides with the TSO. Under a cost-plus or rate-of-return regime, volume risk is borne by network users, but only to the extent that demand fluctuations impact the costs of the regulated business, in which case these would be compensated through network tariffs.

Hence, where realised demand differs from that which is originally forecast, tariff risks arise that must be borne by either the TSOs or transmission network users. From an efficiency perspective, this risk ought to be placed on the party that is better placed to manage the risk (or where its impacts are minimised). For gas transmission networks, and provided the demand forecasts are not grossly mis-specified, the costs of the network will vary only slightly with demand (as most costs are fixed in the short term). **This suggests that the risk exposure should be passed to network users (as it is under a revenue cap)**, since TSOs have limited ability to manage the risk and the risk is diversified by spreading it across a wider group. As mentioned above, this also ought to allow TSOs to access lower borrowing costs.

Cost risk

In respect of cost risk, price and revenue caps do not display many differences between them as opposed to cost-plus regimes. That is, **under both price and revenue caps, the risk**

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[63] This is not invariably true because depending on the regulatory treatment of capital expenditure and the cost structure of the firm, there may still be an incentive for over-estimating future demand.

of cost differences are borne by the regulated company, whereas under cost-plus and rate of return regimes the risk is passed on to network users. This means that under the incentive-based arrangements (price and revenue caps) cost savings are retained (which then provides the incentive for pursuing efficiency gains in the first place), but cost over-runs are also borne by the companies (at least for controllable costs)[64], which is compatible with placing risk with the party that is better able to manage it. That is, as discussed in Section 3 of Part I of this Report, the issue of cost risk allocation raises the **fundamental trade-off between efficiency (under incentive arrangements), on the one hand, and certain cost recovery on the other (with cost-plus/RoR frameworks)**.

Which is preferable, as with other elements of the framework, depends on the circumstances and objectives of the regime, including the other elements being discussed in this Section. In addition, incentive regulation is more informationally demanding in that it requires the regulator to set a revenue allowance that is not 'too high' – if the regulator is unable to obtain sufficiently robust information on the regulated business' costs, rate of return regulation may achieve better outcomes. This might (partly) explain the continued reliance in the EU among many NRAs on a cost-plus regime for the most significant component of TSO spending (ie capital expenditures).

15.1.3 Other regulatory and customer issues

Tariff stability

As highlighted several times already, a **revenue cap** ensures revenue stability for the regulated TSO. The flip-side of this however is that if demand differs compared to forecast and changes from year to year (as it invariably does), **individual tariffs will be relatively more volatile**. This is because tariffs are regularly adjusted for under and over-recoveries through the regulatory account. Moreover, as the adjustment is based on the revenue collected in the previous year(s), it might bear no connection to demand in the forthcoming year(s). For example, if demand is unexpectedly high (possibly due to a particularly cold winter), then a TSO would recover more than its allowed revenue. In the subsequent year(s), tariffs would be reduced to compensate for this over-recovery (irrespective of the projected demand for the upcoming year).

In practice, tariff volatility under a revenue cap might not be significant, as there is the possibility of **smoothing revenues and depleting the regulatory account over a longer period**. Indeed, this seems to be the approach that some of the NRAs are already adopting. For example, over half the NRAs undertake revenue reconciliations between regulatory periods (rather than annually), presumably for this reason. Also, to avoid steep tariff changes, Italy, for example, spreads the adjustment over four years when the revenue reconciliation is more than 2% of allowed revenues.

Under a price cap, tariffs are more stable within a regulatory period but there might be **large changes *between* regulatory periods**. This happens because the demand forecasts used to set the price cap are made only periodically according to the regulatory cycle, which in most cases is four to five years. Under revenue caps, by contrast, demand forecasts are usually updated annually, which should lower the likelihood of step changes in tariffs in the next regulatory period.

[64] Subject to any other incentive or sharing arrangements that might be in place.

Under **cost-plus arrangements**, tariffs would generally be **more volatile** as they track changes in costs. The degree of volatility would depend on the cost structure of the regulated businesses (fixed versus variable costs) and their investment programme. While most TSO costs would be expected to be fixed in the short term (lowering volatility), investments can be lumpy (which would increase volatility and potentially entail steep changes in tariffs).

Regulatory gaming

Both **revenue and price caps** (and other similar incentive-based regimes) **are susceptible to regulatory gaming**. Recall that a fundamental objective of these frameworks is to encourage companies to pursue efficiencies and therefore underspend compared to their revenue allowances. This increases company profitability and, in principle, reveals the true costs of the transmission network which can be taken into account in the revenue determination for the subsequent regulatory period. However, as profitability is determined by the difference between forecasted/allowed expenditure versus actual expenditure, there is **an equivalent incentive to raise the cost forecast/allowance in the first place** as part of the revenue setting process (rather than or in addition to improving operational and investment performance). This includes an incentive to include capital expenditures as part of the revenue determination process (and therefore earn return and depreciation), but then deferring projects until the next regulatory period (in the absence of other incentives or conditions). This raises **a fundamental dilemma for incentive-based regimes – how to preserve the incentives for cost minimisation without encouraging (excessive) gaming?** This largely depends on the other incentive features of the regulatory framework and the approach and robustness of cost assessment (which is discussed further below).

Price caps have the added problem of creating an incentive to also game the demand forecast. This is because revenues (and profitability) increase if actual demand exceeds that which is forecasted, particularly in the presence of large fixed costs (where marginal costs are low and therefore are likely to be significantly below the regulated cap). In other words, **under a price cap, a regulated firm has an incentive to bias down its demand forecasts**, and then to act to maximise demand (and its profits).

While **cost-plus regimes** are not subject to the same gaming incentives, they do **suffer** as already discussed elsewhere **from the 'Averch-Johnson effect'**, in which firms subject to such regulation have incentives to overinvest to increase the capital base on which they are guaranteed a return and have little incentive to pursue efficiencies.

15.1.4 Summary

The choice between revenue control mechanisms is not unambiguous, and is likely to depend on the circumstances of the country/sector and also the weighting placed on different objectives by the NRAs and other stakeholders. A summary of our assessment of the main regimes is provided in Table 23 below.

Table 23 Summary assessment of revenue control mechanisms

Criteria	Revenue cap	Price cap	Hybrid	Cost-plus/RoR
Productive efficiency	✓✓ Reducing costs maximises profits	✓✓ Reducing costs maximises profits	✓ Reducing costs may maximise profits, but incentive is muted depending on hybrid design (eg might apply just to opex)	✕ No strong incentives for cost minimisation
Dynamic efficiency	✓ May be consistent with profit maximisation, but also incentive to delay investments	✓ Mixed incentives – innovations that reduce future throughput discouraged, but incentive to meet and expand demand	✓ Mixed incentives – depending on the hybrid design, will display features of the other models	✓ Mixed incentives – no strong incentive for cost minimisation, but consistent with expanded service coverage
Allocative efficiency	✓ Generally associated with more passive pricing strategies but also consistent with demand management	✓ Theoretically provides greater incentives for efficient pricing, but not consistent with demand management	✕ Incentives depend on the hybrid design, but unlikely to be as high as under pure revenue or price caps	✕ No strong incentives for efficient pricing or demand management
Volume risk allocation	✓✓ Risk placed on network users (which is consistent with the prevalence of fixed costs in gas transmission)	✕ Risk placed on the regulated firm, although little ability for TSO to manage volume risk in the short term	Uncertain	✓ Risk shared between regulated firm and network users – if volumes affect costs, then risk passes to users (and vice versa)
Cost risk allocation	✓✓ Cost deviations generally borne by the regulated business	✓✓ Cost deviations generally borne by the regulated business	✓ Mixed impacts, depending on design (eg opex cost differences borne by firm, but investment costs differences borne by network users)	✕ Cost differences are fully passed through to network users
Tariff stability	✓ Tariffs vary with volumes (to maintain revenues) so are volatile, but can be smoothed over time	✓ Tariffs stable within a regulatory period, but there could be step changes between regulatory periods when volumes are re-forecast	✕ Mixed impacts, but volatility likely to be higher than revenue and price caps (especially where capital expenditures are cost-plus)	✕ Tariffs likely to be volatile given that they closely track cost variability
Regulatory gaming	✓ Incentive to forecast high costs	✕ Incentive to forecast high costs and low demand	Uncertain – depends on design	✓ Susceptible to gold plating investments (to increase returns)

Source: ECA

✕ Little consistency with the criterion

✓ Some consistency with the criterion

✓✓ Potentially strong compatibility with the criterion

Incentive-based regimes (revenue and price caps) theoretically provide much stronger incentives than cost-plus/RoR regimes on minimising costs and place the risk of any cost deviations on the TSO rather than network users, which is consistent with efficient risk allocation (if costs are controllable).

The impacts on dynamic and allocative efficiency are ambiguous, with the different control mechanisms providing mixed incentives (of a different type each), although issues of allocative efficiency are directly regulated now through the tariff structure provisions of the EU Gas Network Tariff Code.

Revenue caps score well in relation to volume risk, but this is also then associated with higher tariff instability (although in practice this can be managed through revenue smoothing mechanisms). Finally, incentive-based regimes (particularly price caps) are subject to regulatory gaming, but cost-plus/RoR regimes are also not immune to this, given the bias to increasing the capital base (and therefore returns).

On balance, **most EU NRAs seemingly place more weight on efficiency incentives and removing volume risk from the TSOs**, which should therefore (other things equal) lower the cost of capital, and they therefore favour revenue caps. However, **a significant number continue to use cost-plus arrangements for capital expenditures**. We suspect that this might largely derive from the gaming issues discussed above and a concern that TSOs do not have an incentive to artificially inflate (and therefore profit from) cost forecasts. This (ie obtaining accurate costs forecasts) is one of the largest challenges of regulation and is discussed in the section immediately below.

15.2 Determining and setting expenditures

A major goal of the economic regulation of gas transmission is to ensure that TSOs are unable to set tariffs that exceed efficient costs. Hence, setting the revenues at a level that is commensurate with 'efficient costs' (given reliability and security of supply standards) is at the centre of NRAs' tasks and of the challenges they face. The difficulty arises because of the **information asymmetries between the TSO businesses and the regulators** – the latter have imperfect information about the TSOs' actual costs, demand and service quality (the TSO has more information about these attributes than the regulator or other interested parties), but **regulators are required to make judgements about these matters so that they can set revenues broadly equal to efficient costs and/or to define the magnitude of (and the time for closing) any efficiency gaps**.

As discussed in Section 11 of this Report, the NRAs employ various methods to assess the proposed expenditures of the TSOs and based on these set the associated allowances that enter the revenue calculation. Summarising the findings of the NRA survey:

- **Bottom-up assessments are by far the most common method employed for both operating and capital expenditures** (and in many cases is the only method applied)
- **TOTEX approaches are limited** to Germany, the Netherlands and Great Britain and, for some cost components, to France

- **Benchmarking is not widely established** and applied for gas transmission by EU NRAs

- In most **cases a more rigorous assessment is undertaken of operating rather than capital expenditures** (this is supported, for example, by the absence of efficiency factors applied to capital expenditure), despite TSO costs being dominated by capital expenditures – this is not surprising given the complexity of investment, its largely non-recurring nature and its heterogeneity across TSO businesses

- Several NRAs have adopted **an approach for opex that requires the TSOs to improve productivity over time relative to existing costs** in a base year ('historical outturn opex approach').

The relative merits and drawbacks of the different approaches to cost assessment were discussed in Section 4 of this Report. Here, we broadly employ our adopted assessment framework to draw out some further insights in the specific context of the methods currently applied by the NRAs. In particular, we explore two main questions given the state of development of cost assessment by EU NRAs:

1. Do NRAs need to devote more effort (and resources) to TSO cost assessment? – the answer to this question is closely tied to the purpose of cost assessment and therefore the efficiency criterion - and, if so, is there merit in moving to more 'sophisticated' forms of assessment such as cost benchmarking and/or TOTEX approaches? – this depends on the assumed degree of inefficiency in the gas TSO sector (versus the added cost and complexity of more 'advanced' or detailed cost assessment).

2. If more detailed cost assessment is justified, how could these other approaches be adopted and applied?

15.2.1 Is greater scrutiny of TSO costs warranted?

Economic efficiency is at the heart of any cost assessment method as the aspiration is that TSO costs are minimised (productive efficiency), tariffs are then set in accordance with efficient costs (allocative efficiency) and efficiencies are also maximised over time (dynamic efficiency). While all three efficiency aspects are important, most cost assessment focuses on productive and dynamic efficiency. In this respect, and summarising the discussion in Section 4 of the Report:

- **Top-down assessments are likely to provide stronger incentives for efficiency improvements** (while ensuring the financial sustainability of the regulated firms given the more holistic assessment of costs) **compared to bottom-up assessments** which focus on individual cost items or categories and therefore might not sufficiently capture substitution possibilities (and are more susceptible to TSOs exploiting their informational advantage)

- The use of cost **benchmarking is likely to provide the strongest incentives for efficiency** given that, depending on the form, scope and application of the benchmarking analysis, revenues are partly or wholly decoupled from the TSO businesses' actual costs, encouraging them to minimise costs and thereby maximise profits – we note again that it is uncertain from the survey results whether those NRAs only employing top-down assessments accompany them with some form of benchmarking; we would posit that the assessments would be of limited value in the absence of some cost comparison technique

- However, **the adoption of benchmarking (regardless of the technique or approach) increases the complexity of the regulatory regime** as it is a demanding quantitative task and is subject to considerable data errors, assumptions and (potentially subjective) choices, which in turn places a **significant burden on regulators to ensure that the benchmarking employed and its results are accurate, reliable and robust**.

A summary review of the cost assessment methods, building on the above considerations and setting them against (a subset of) the evaluation criteria is provided in the table below.

Table 24 Summary evaluation of cost assessment methods

Criteria	Bottom-up	Top-down	Benchmarking	TOTEX
Efficiency	✕ Limited efficiency incentives, given focus on individual costs	✓ Holistic approach should deliver stronger efficiency incentives	✓ Strong efficiency incentives given revenue-cost decoupling	✓✓ In principle, most consistent with efficiency as it also removes incentive to favour one type of expenditure to increase profits
Regulatory cost/complexity	✓✓ Least costly approach as only firm-specific costs are assessed (albeit generally requires detailed examination of individual cost items/categories)	✓ Requires access to a dataset of (partial) efficiency or productivity measures of comparator companies	✕ Extensive and complex data and modelling requirements	✕ Extensive and complex data and modelling requirements plus major change to regulatory regime and approach

Source: ECA

✕ Little consistency with the criterion

✓ Some consistency with the criterion

✓✓ Potentially strong compatibility with the criterion

As shown in the table, while the more sophisticated cost assessment methods are relatively more consistent with efficiency principles theoretically, there are correspondingly much more intensive and complex data and analytical requirements associated with these.

A key question then (given the current heavy reliance on bottom-up assessments) is whether the increased regulatory burden of employing benchmarking or other related tools can be justified. The answer depends on the current level of inefficiency in the EU TSO sector. Some inefficiency is likely to exist (it does even in highly competitive markets), but **the critical point is whether the inefficiency is sufficiently large to necessitate closer scrutiny of TSO costs and the use of more rigorous cost assessment methods**. The question is somewhat circular, as benchmarking and statistical analysis would be needed in the first instance to provide empirical evidence for the presence or absence of large inefficiencies. However, *a priori*, there are grounds for believing that inefficiencies are likely to be material:

- by virtue of their monopoly status, TSOs are shielded from competition (and the absence of competition is generally associated with reduced efficiency)

- many of the EU TSOs are state-owned businesses and cannot be acquired by or merged with other companies (the threat of hostile takeovers can act as a discipline for operating efficiently)

- TSOs cannot be allowed to become insolvent – regulators generally have a legal obligation to ensure the financial viability of the TSOs and in any case TSO bankruptcy would not be tolerated (politically and socially) given the large disruption costs and security of supply concerns

- whatever evidence does exist (notwithstanding data and sampling size deficiencies) from cost benchmarking studies of network industries (such as electricity transmission and distribution where benchmarking is more prevalent) suggests that there are very large divergences between the most and least efficient businesses.

In principle therefore, it would seem that **more detailed scrutiny of TSO costs might be warranted**.

It is worth noting that what we termed the "**historical outturn opex" approach** in Section 11.1.1 used by some NRAs for setting opex allowances does not necessarily address the issue of productive inefficiency. This approach, which entails reimbursing the TSO's existing costs in a base year and then adjusting allowances in succeeding periods using an efficiency factor (based on an estimate of the rate of productivity change) has the effect of eliminating rents (allocative efficiency), but not necessarily technical inefficiencies[65]. However, this approach **does have several important advantages including its relative simplicity and the strong incentives it provides for cost reduction over time (dynamic efficiency)**.

15.2.2 How should more 'advanced' assessment methods be employed?

There are several options to using cost benchmarking, including to:

1. Act as a diagnostic tool to help assess the reasonableness of bottom-up proposals

2. Set expenditure allowances within a building block framework, for example, by combining (partial productivity measures) with some top-down assessment of particular cost categories

3. Set the efficiency factor, based on total factor productivity growth, to set operating cost or revenue growth

4. Provide information to network users and others (through regulatory reporting), thereby providing pressure for improved performance by TSOs

[65] Some NRAs stated that base year opex is sometimes adjusted to be brought to an 'efficient level'. But it is unclear how this is done in practice and it would appear therefore that the issue of some form of benchmarking re-emerges.

5. Set revenues based purely on the cost benchmarking results (as is common under TOTEX approaches).

While over time cost benchmarking may play a more deterministic role in setting revenue allowances (as with TOTEX approaches under point 5 above), we would expect that for most NRAs the more appropriate use of benchmarking would be for one (or more) of the first three listed purposes ie effectively to **provide a challenge to TSO forecasts and/or provide a path for the achievement of efficiency and productivity gains over time**. However, even at this level, considerable effort would be needed in determining the information to collect, and standardising data collection and benchmarking processes. We would suggest that these processes are best defined at an EU-wide level, if possible, and the information thereby generated could also be (subject to any confidentiality provisions) published in regular benchmarking reports (as per point 4), which of themselves can provide incentives for improved network performance.

15.3 The regulatory asset base

As we discussed in Section 5 of the Report, the concept of the RAB provides the foundation for the confidence of investing in the maintenance and expansion of the transmission network. Therefore, an important regulatory objective is **to underpin confidence that the opening value of, and the basis for rolling forward, the RAB are stable**, thereby providing a firm foundation for future investment decisions.

Given the above and the fact that all EU regimes are now well established, **there is no rationale in our view in departing from the adopted starting asset values**. **This would create considerable regulatory risk and potentially undermine future investment** or at least result in TSOs requesting a higher cost of capital to compensate them for the added risk and uncertainty created by the precedent of revising established asset values. Because the costs are sunk, there is also no clear economic rationale for any change (to counterbalance the added regulatory risk). Hence, it would only be appropriate to depart from existing values if there is a perception of inequity that is strong enough to render the RAB unsustainable without a correction (we are not aware that this is the case in any jurisdiction).

For similar reasons, **we would favour that the entire RAB *not* be periodically revalued using replacement costs**[66]. This is because:

- Replacement cost methodologies introduce greater regulatory risk for TSOs and investors given the uncertainty associated with replacement values and would likely need an increased cost of capital to offset the risk

- Replacement cost valuations add significantly to the complexity and cost of the regulatory regime and they are sensitive to the assumptions used, which can introduce subjectivity (particularly when this entails optimising the configuration of the network) and therefore open up regulatory decisions to challenge and appeal thereby further raising costs

[66] We note that as elsewhere in this Report, our reference to replacement cost methods is to any of several methodologies employed for expressing asset values at their current cost (and not the periodic indexation of the asset base for reasons of consistency with the application of a real cost of capital).

- It is unclear how upgrades would be treated under a replacement cost approach, given that an optimised network may be cheaper to upgrade than the actual legacy network, potentially threatening future investment

- In most cases, adopting a replacement cost methodology would be a major change from the existing regime (only two NRAs employ this approach currently), which might then fundamentally alter the current incentive schemes and regulatory approach.

Nevertheless, we do believe that there ought to be **greater scrutiny of actual expenditure that enters the RAB, which currently occurs in an automatic way in many cases or with limited review** (see Section 12.4), particularly given the heavy reliance on cost-plus arrangements for the capital expenditure component of revenue allowances and the absence of other incentive mechanisms for addressing overspends. We discuss this issue further in the sub-Section below.

15.3.1 *Ex post* reviews of capital expenditure

Currently, most NRAs apply a form of incentive regulation to opex, which although differs in design, generally rewards TSOs for operating efficiency gains (and some also penalise them for operating efficiency losses). Capital expenditure, on the other hand, is not subject to such incentive mechanisms and/or is treated as cost-plus with almost automatic updating of the RAB for actually incurred capital expenditure or investment costs. **This differential treatment creates a capex bias (ie a preference for capital expenditure over operating expenditure)** - for example, TSOs might favour asset replacement which would increase RAB and therefore future returns, rather than ongoing maintenance which would increase opex and therefore potentially lower returns and/or incur penalties, even if in net present value terms, it would be lower cost to undertake ongoing maintenance.

Subject to any other incentive mechanisms in place (such as TOTEX approaches, or sharing mechanisms for overspends), it therefore might be good regulatory practice to allow regulators the flexibility of undertaking *ex post* reviews of TSO capital spending, particularly where this materially exceeds previously forecast levels. The key feature of such an approach would be that **NRAs only allow capital expenditure that they deem prudent and efficient (given the information available to the TSOs at the time of their investment decisions) to be rolled into the RAB**. We note that this would not entail reoptimising the entire RAB (as per a replacement cost methodology).

There are nevertheless some significant drawbacks to such reviews including:

- practical difficulties in demonstrating that spending, either on an individual project or across a portfolio, was inefficient

- the risk of mistakenly identifying an efficient investment as inefficient (which might need to be reflected in a higher cost of capital)

- a greater level of intrusion and micromanagement (which would appear to partly defeat the purpose of incentive arrangements).

For these reasons, **we would suggest that such reviews be used sparingly and as a complement to other *ex ante* incentive arrangements**, and only apply in limited cases where there is potentially obvious evidence of overspending.

15.4 The weighted average cost of capital

The setting of TSO revenues requires the *estimation* of the return on capital for the business. The allowed cost of capital is therefore likely to differ from the *actual* cost of capital, which could then distort investment decisions. The implications of this are that:

- **If the cost of capital is set too low**, tariffs for network users would be lower (in the short term) but it would make it difficult for TSOs to recover their efficient costs in the long term which would **deter investment** and ultimately result in deteriorating infrastructure and/or quality of service.

- **If the cost of capital is set too high**, it would create **incentives to over-invest** and result in higher tariffs (however, given the generally long-lived nature of TSO assets, the return would need to be systematically over-estimated over many regulatory periods).

Either result would be inconsistent with productive and allocative efficiency (as costs and tariffs would either be set too high or too low compared to efficient costs). Regulatory authorities have generally concluded that the damage to network user interests from overstating the WACC may be smaller than the harm from understating it and therefore generally err on the side of caution in setting the WACC parameters, while recognising that users pay directly and more than necessary if the WACC is set too high.

Either way, **efficiency considerations would require that the cost of capital is set 'accurately'**. However, there are practical difficulties to this, especially for the cost of equity, which can only be partially observed through *realised* returns on comparable assets (but even this cannot be measured reliably and may not in any case reflect *expected* future returns).

In the case of debt costs, it is possible to compare realised borrowing costs with those estimated and assumed when setting allowed revenues. However, as debt costs vary depending on company-specific characteristics, it is unlikely that a particular prescribed methodology will be applicable or desirable in all cases.

The implications of the foregoing is that an evaluation of the approaches to setting the cost of capital is difficult and there is **no unambiguous way of choosing between alternative estimation methods**, all of which have their own theoretical strengths and weaknesses. Consequently, **our discussion below attempts instead to draw out some general principles or issues that could be considered by the EU NRAs when calculating the cost of capital, while recognising that the detailed rules and design will remain with individual authorities**. However, the discussion is still guided by the assessment criteria and particularly by issues of efficiency, and flexibility versus certainty (and therefore risk).

15.4.1 High-level principles for setting the cost of capital

The survey demonstrated that the almost universal approach to estimating the cost of equity by NRAs is the conventional CAPM model. Moreover, in almost all cases, this is exclusively relied upon and is not cross-checked against other estimation methods. Finally, many NRAs apply a mechanistic approach to determining some of the WACC parameters, such as the risk-free rate, the market risk premium and the equity beta.

Notwithstanding the general similarity of approaches and methodologies used, however, the NRAs arrive at very different values for the underlying parameters. This is to be expected, given that estimating the cost of capital **ultimately requires a regulator to exercise judgement about the analytical techniques and evidence that should be employed** to derive the estimate, as well as taking into account the characteristics of the particular regulatory regime and country circumstances. However, we believe that there might be merit in **developing some overarching principles and guidelines for setting the WACC that could be employed at the EU-level, while allowing sufficient flexibility to individual NRAs**. These principles would involve setting out the approach to calculating the cost of equity and could include consideration of the following key issues or features:

- **Cost of capital objective** – as mentioned above, estimating the cost of capital requires judgement but where this is the case it is best (for reasons of transparency and greater certainty for investors and network users) that it be exercised by reference to specific objectives. Our interpretation of the EU legislative framework and current practice among many NRAs is that **the cost of capital should be set so that it reflects efficient financing costs** (versus, for example, by reference to some conception of a 'fair' return). If this is true, it would be worthwhile making this objective (or whatever other objectives are considered important) explicit (if not already stipulated in legislation or other guiding instruments).

  Also, to the degree that we were able to ascertain, most NRAs did not appear to systematically assess the risk profile of the TSOs in setting the cost of capital. Hence, consideration could be given to explicitly **recognising that the assessment should be couched in terms of risk to cash flows** given that assessments of returns are primarily driven by assessments of risk (although these would need to be undertaken on an equivalent basis when comparing to other firms, ie country and framework-specific matters affecting the risk assessment must be considered). For example, any estimation method is likely to produce a plausible range for the cost of equity; selecting a point within that reasonable range is a matter of judgement, but that judgement can be guided by considering the riskiness of the relevant firm's cash flows relative to the riskiness of the comparable firms used to generate the cost of equity estimate. How such an assessment is conducted is not precise, but the key is **to examine the degree to which the regulated business is exposed to systematic risk** (a regulated entity might face an array of financial incentives that inject volatility into its realised returns, but it is only those factors that create exposure to systematic risk that are important from a cost of capital perspective). By way of example, an entity subject to a price cap would face greater systematic risk than a revenue-capped entity, or the greater the size of a regulated firm's opex relative to its RAB generally implies higher risk and beta (as a lower proportion of revenue is accounted for by operating cashflow ie return and depreciation).

- **WACC basis** (pre or post tax, real or nominal, vanilla) – as we documented earlier in this Report there are various approaches used by the NRAs in setting the WACC or cost of equity in relation to the tax and price basis employed. From a theoretical perspective, the choice of method should not affect the outcomes for the TSO businesses and network users, so there is no efficiency or economic imperative to adopting a common approach. However, using a common method does have practical benefits in that the **cost of capital can then be more readily compared** on a consistent basis. At a minimum, a requirement to publish the WACC on a consistent basis (irrespective of the underlying approach used) would facilitate such comparisons.

- **Methodology and estimation methods** – while CAPM can remain the foundation model for estimating the cost of equity, consideration could be given to **allowing regulators the flexibility to examine a range of estimation methods, market data and other evidence**. Despite the widespread use of CAPM, it is not the only estimation method available; moreover, there is no single model that precisely determines the cost of equity. In these circumstances, there might be value in complementing the CAPM analysis with other approaches (such as dividend growth models), in order to sense check the results and consider whether in certain prevailing market conditions some weight ought to be given to other factors. While this necessarily introduces some discretion to the estimation process, it might be necessary to protect either the TSOs or network users when market conditions change adversely (the other elements of the framework being outlined here should hopefully provide a more certain framework around the *process* of estimation to provide investors and users with sufficient confidence of the objectiveness of the assessment). In any event, any such analysis would need to avoid introducing opportunistic behaviour (whether by the regulator or the TSO) and rely on methods that are generally accepted and/or applied by academics and/or leading regulatory practitioners.

- **Deterministic estimation or regulatory flexibility** – as mentioned above, in many cases NRAs are employing mechanistic rules for setting certain cost of capital parameters, even within the CAPM framework (such as the risk-free rate which is commonly calculated by reference to 10-year nominal government bonds of Member States). This approach has the advantage of creating relatively greater certainty about the method of calculating the cost of equity (or at least for some components of it, like the risk-free rate), and can be viewed as more objective (particularly where there are many regulated entities) thereby providing greater protection against appeals to regulatory decisions. Nevertheless, the mechanistic approach might be too limiting. For example, yields on nominal government bonds are affected by inflation rate expectations, and therefore yields on inflation-adjusted bonds might provide better insight into the risk-free rate than yields on nominal bonds. While we recognise that a fully liquid market for Euro-zone inflation indexed bonds might not yet exist, this may not be the case in the future. This is just one example of how NRAs may wish to depart from their current methodology or practices in their cost of capital assessment. This would therefore argue against a set of prescriptive rules for estimating WACC or cost of equity parameters.

We concede that such an approach creates tension between certainty and flexibility in the cost of capital framework. However, **the application of rigid rules could be detrimental to either TSO or network user interests when market conditions change adversely**. Moreover, it is unlikely that consideration of market returns and risks remains static over time and under all circumstances, so placing certainty (as important as it is) above all other considerations could have considerable drawbacks.

- **Transparency and accountability** – a key element of this part of the regulatory framework as with any aspect of the revenue determination we believe would benefit from greater transparency in each jurisdiction, entailing a full and considered explanation for cost of capital decisions. Furthermore, we would suggest that **there might be merit in establishing a forum at EU level** (or building into the work programme of existing fora) for developing the principles enunciated above (and others) that can act as general guidelines for NRAs when setting the cost of capital. This forum could also be used for reporting on and learning from the approaches used in other jurisdictions (and in latest academic thinking), explaining why different approaches are taken by certain NRAs or in specific circumstances, and reviewing the cost of capital principles, guidelines and approaches at appropriate intervals.

In relation to the cost of debt and although this is assessed separately by some NRAs, we believe that it should be considered similarly to the cost of equity as both are part of the allowed rate of return. This would therefore mean that **the cost of debt that is set by NRAs should also reflect efficient financing costs** (rather than the actual costs of the specific TSO) ie it would be guided by the same cost of capital objective stated above. This in any case seems to be the general approach adopted by most NRAs.

Beyond this, efficient debt management practices are likely to differ according to firm-specific characteristics including the size of the business, the asset base of the TSO, the firm's ownership structure, and the prevailing macroeconomic conditions of the country. Hence, once again it is **unlikely that a particular approach could be mandated that would be appropriate in all circumstances**. However, we would suggest that the approach to setting debt costs could be included in the work programme of the cost of capital forum mentioned above. This could consider, for example, **the factors and characteristics that NRAs should take into account in designing their preferred approach** whether it be a prevailing debt cost approach, or a historical estimate or some combination of the two.

15.5 Other regulatory mechanisms

As reported in Section 14, **NRAs generally make limited use of incentive mechanisms for dealing with efficiency gains and losses and quality aspects of TSO transmission services**.

Regarding the former (ie efficiency incentives), the incentive mechanisms that are in place are generally limited to opex with savings and losses kept/incurred for the duration of the regulatory period (which means that incentives are not constant through time), or where they are time-neural they do not address the issue of capex bias (given that opex outperformance is rewarded while actual capital expenditure is generally rolled into the RAB with limited review and/or is not subject to any corresponding sharing mechanism).

There is therefore a case for equalising the incentive rates for opex and capital expenditure. This can be achieved either by adopting TOTEX approaches or introducing comparable incentive mechanisms for capital expenditure to complement existing opex efficiency schemes.

In relation to quality, there is a risk that in an effort to reduce costs (especially under incentive-based regimes that reward cost savings) TSOs do so at the expense of quality. There is therefore a case for the **more widespread use and development of incentives to maintain or improve service quality levels** (as well as to reduce costs).

15.6 Final observations

Summarising our assessment of the EU methodologies and distilling some key lessons, we note the following:

- The most common NRA practice is to employ **revenue caps** for controlling allowed revenues (whether in totality or for the opex component), which we consider to be **most consistent with promoting efficiency and with the fact that volume risk is not easily managed by TSOs**. Concerns about tariff instability under revenue cap regimes can be managed through smoothing mechanisms, while the potential for inefficient pricing is now addressed directly by the tariff structure provisions of the Gas Tariff Network Code. **Consideration could be given to expanding the revenue cap to cover the entire revenue allowance** (and not just opex), although this would need to be accompanied by other mechanisms to ensure efficient costs and incentives are set (see below).

- Cost assessment approaches in many jurisdictions remain embryonic and relatively passive and therefore **greater regulatory effort is required to challenge the cost assumptions of the TSOs** and to provide more 'stretching' efficiency targets. This might need to consider the possibility of employing cost benchmarking techniques and measures as a way of challenging TSO forecasts. There may also be a case for establishing an EU-wide procedure for collecting standardised information from TSOs and publishing data on comparative network performance.

- **There are no strong efficiency grounds for revisiting opening (or starting) asset values** and unless it is considered that there are large imbalances (between TSOs and network users) it is best to retain these values to underpin confidence in undertaking future investment. Also, NRAs, with few exceptions, broadly favour rolling forward actual expenditure rather than periodically revaluing and updating the RAB. This appears to us consistent with minimising regulatory risk and complexity, lowering the cost of capital and promoting investment.

- **There needs to be greater scrutiny of new investment and capital expenditure and/or incentives to minimise costs and remove potential biases for undertaking capital expenditure**. This can be achieved in several ways and needs careful consideration by NRAs of the relative incentive properties of the various mechanisms or package of measures:

- **TOTEX approaches** – most EU regimes separately assess operating and capital expenditures; combining the assessment under a TOTEX approach could remove any biases for capital expenditure solutions and provide more flexibility to achieve efficiency gains. However, the adoption of such a regime requires NRAs to undertake considerable development work and would represent a major change from current regulatory practice, so beyond the current NRAs using TOTEX this is likely to be adopted in just a limited number of countries at the present time.

- ***Ex post* reviews of capital expenditure** – especially in the context of cost-plus arrangements and in the absence of other efficiency incentives, NRAs should employ *ex post* reviews to ensure that only prudent and efficient investment is rolled into regulatory asset bases. Even in the presence of other regulatory mechanisms, such reviews could be used sparingly where there is potentially credible evidence of overspending.

- **Incentive mechanisms** – the current focus by most NRAs on operational outperformance and the differential treatment of opex and capital expenditures might create a bias for the latter, while many of the opex incentives employed by EU NRAs do not provide consistent incentives throughout the regulatory period. NRAs should therefore consider the design and implementation of mechanisms that ensure efficient spending and its neutral treatment (regarding the choice of both timing and expenditure type).

- **For the cost of capital, we believe it neither necessary nor desirable to establish prescriptive rules and a common EU approach**. But, there would be value in developing **high-level guidance at the EU level** which would then be employed by NRAs for their more detailed rules, and to then have greater sharing of thinking and analysis between NRAs, as well as periodic reviews of the underlying principles to reflect current best or common practice. A key element of the guidance would be balancing the need for TSO certainty against NRA flexibility to have regard to multiple estimation methods and market evidence given the inherent difficulty in precisely estimating the cost of capital.

- **Quality of the transmission network service needs to be given greater prominence in NRA regulatory frameworks**, especially if moving from cost-plus arrangements to a greater reliance on efficiency incentives and incentive-based regulation – if the regulatory regime remains focused just on reducing costs, this is likely to lead to sub-optimal levels of quality. Consideration also needs to be given to relevant performance metrics for gas transmission and the value that is placed on these by network users if an efficient and effective performance regime is to be established in the various jurisdictions. Such metrics might typically cover factors such as system reliability, damage incidents, gas leaks and unaccounted for gas, emergency responses, asset management practices, pipeline corrosion and community liaison.

- **Reporting should be improved** – incentive-based regulation, in particular, requires detailed reporting of costs and other parameters of performance. Although not emphasised earlier in this Report, whatever regulatory reporting is currently undertaken, it is mostly focused on financial matters, with little or no attention to physical system data. Hence, while regulatory reports examine monies received and spent, and the financial characteristics of assets, there is rarely quantification of what assets are built, maintained or operated to deliver gas transmission services. Consideration should also be given to developing a common framework for collecting TSO data, particularly if NRAs choose to employ more benchmarking methods in their cost assessments.

Part III: Country fact sheets and questionnaire

16 Country fact sheets

16.1 Revenue cap regimes

16.1.1 Belgium

Belgium		
Regulatory, market and policy framework		
Regulator	Commission for Electricity and Gas Regulation (CREG)	
TSO(s)	Fluxys Belgium SA	
Customer mix	Residential/commercial	52%
	Large industrial	23%
	Power generation	25%
Ratio of transit to national flows	1.38	
Network age and length	Pipeline length	4,100 km
	Original operation	1929
Regulatory governance and process		
Entity that establishes the methodology and sets allowed/target revenues	CREG (NRA)	
Length of revenue setting process	5.5 months	
Parties that can appeal NRA-determined revenues	TSO, transmission system users, any stakeholders	
Type of appeal that is allowed	Full merits review	
Overall framework for setting allowed revenues		
Type of regulation	Revenue cap	
Approach to assembling the cost base	Building block	
Duration of regulatory period	4 years	
Determining and setting operating expenditures		
Cost categories partially or fully passed through	'Fiscal disparities', taxes (including company tax), debt costs and commodity costs (fuel gas)	
Methods and approaches to assessing and setting opex allowances	Top-down assessment	
Inclusion of efficiency or productivity improvements	No	
Efficiency factors used in most recent regulatory period	N/A	
Treatment of gas shrinkage	Losses/shrinkage (gas consumed in compressors, heaters, and electricity for compressors) is treated as pass-through cost	

Belgium

Determining and setting capital expenditures		
Methods and approaches to assessing and setting allowances	Business case analysis: the NRA performs a cost-benefit analysis for any investment above €10m. However, investments are typically allowed if tariffs do not need to be raised to accommodate them. Specialised consultants hired to estimate the reasonable costs for investments with many technical requirements.	
Use of uncertainty mechanisms	Budget ceiling on a case-by-case basis.	
Inclusion of efficiency or productivity improvements	No	
Efficiency factors used in most recent regulatory period	N/A	
Use of ex post reviews before rolling capital expenditure or assets into the RAB	No	
Use of tendering for large system expansions	Yes	
Regulatory asset base (RAB)		
Method used for setting the opening asset value (at the time of establishing the new regulatory framework)	Depreciated replacement cost Informed by reports from independent experts	
Depreciation of closing asset value as a single asset or as separate asset categories	Separate asset categories	
Revaluation of the RAB	No	
Major assets included in the RAB	Pipelines, compressor stations, control stations, metering stations, SCADA stations and systems, metering and regulation stations at the interface with the distribution network, larger consumer connection assets	
Inclusion and treatment of linepack	Included	
Inclusion and treatment of working capital	Yes Apply a formula (negotiated with the TSO/DSO) of 1/12 * new investment for the year + 1/12 * purchases for the year + 50% * dividends	
Timing of rolling investments into the RAB	At time of construction	
Depreciation		
Method	Straight-line Declining balance for a limited number of installations	
Asset lives (for major asset groupings)	Pipelines	50 years (in most cases)
	Compressors	33 years
	Controllers/metering stations	33 years
	SCADA, telecoms	10 years for telecoms 5 years for SCADA

Belgium

<table>
<tr><th colspan="7">Cost of capital and financeability</th></tr>
<tr><td>WACC method</td><td colspan="6">Pre-tax, nominal WACC
Cost of debt is treated as pass-through</td></tr>
<tr><td rowspan="2">WACC value set in the two most recent regulatory periods</td><td colspan="3">Previous regulatory period</td><td colspan="3">Current regulatory period</td></tr>
<tr><td colspan="3">6.55%</td><td colspan="3">3.74%</td></tr>
<tr><td>WACC premium for specific investments or risks</td><td colspan="6">1.25% for investments needed to ensure security of supply</td></tr>
<tr><td>Primary (or only) methodology for setting the cost of equity</td><td colspan="6">Capital Asset Pricing Model (CAPM)</td></tr>
<tr><td>Method for setting the risk-free rate (RFR)</td><td colspan="6">Annual average of 10-year ‘OLO’ (ie linear) bonds issued by the Belgian government (calculated over the 10-year period preceding the review). The allowance is set based on Belgian Bureau du Plan (the Federal Planning Bureau) calculations and then there is a ‘true-up’ ex post based on actual yearly average yields on OLO bonds</td></tr>
<tr><td>Method for setting the equity or market risk premium (MRP/ERP)</td><td colspan="6">Combine the following approaches: 40-year back calculation (of the difference between market returns and the risk free bond return), geometrical average of the Belgian share market-return vs yields on 10-year OLOs, and Dimson, Marsh & Staunton (Crédit Suisse) estimate of the MRP for Belgium (1900-2013). Estimate of MRP is added to the RFR to estimate total market returns. MRP is taken as the average of the arithmetic and geometric averages</td></tr>
<tr><td>Method for establishing the equity beta</td><td colspan="6">Refer to regulatory precedents elsewhere</td></tr>
<tr><td rowspan="3">WACC parameters
(RP = Regulatory Period
CoE = Cost of Equity)</td><td></td><td>RFR</td><td>MRP</td><td>Equity beta</td><td>Asset beta</td><td>CoE</td></tr>
<tr><td>Prev. RP</td><td>4.20%</td><td>3.50%</td><td>0.65</td><td>-</td><td>See below</td></tr>
<tr><td>Current RP</td><td>0.80%</td><td>3.50%</td><td>0.65</td><td>-</td><td>See below</td></tr>
<tr><td rowspan="2">Cost of equity</td><td>Prev. RP</td><td colspan="5">6.48% for equity share up to 33% of RAB
4.90% (=RFR+0.70% premium) for equity share above 33% of RAB</td></tr>
<tr><td>Current RP</td><td colspan="5">3.69% for equity share up to 33% of RAB
1.50% (=RFR+0.70% premium) for equity share above 33% of RAB</td></tr>
<tr><td>Method for setting the cost of debt</td><td colspan="6">Set ex post</td></tr>
<tr><td>Inclusion of debt issuance costs</td><td colspan="6">No</td></tr>
<tr><td rowspan="2">Cost of debt parameters</td><td></td><td colspan="2">Debt premium (if relevant)</td><td colspan="2">Cost of debt (net of issuance costs)</td><td>Debt issuance costs (if relevant)</td></tr>
<tr><td>Previous reg. period</td><td colspan="2">-</td><td colspan="2">4.49% (ex ante)
4.14% (ex post)</td><td>-</td></tr>
</table>

Belgium

	Current regulatory period	-	3.01% (*ex ante*) 2.91% (*ex post*)	-
Gearing approach	Notional (33/67 Equity/Debt ratio)			
	Previous regulatory period	51% (*ex post*)		
	Current regulatory period	52% (*ex post*)		
Financeability assessment	No financeability assessment			
Other regulatory mechanisms (revenue adjustments and incentives)				
Treatment of accumulated over or under-recoveries of revenues	Adjusted both within and between regulatory periods. Over and under-recoveries are fully accounted for in the next regulatory period. Carried forward at a short-term borrowing rate.			
Adjustment mechanisms for differences between forecasted or allowed <u>operating expenditures</u> and realised spend	Applied symmetrically for both outperformance and underperformance. Carried forward at a short-term borrowing rate. A sharing mechanism of 50% is applied on controllable OPEX (in the words of the NRA: “An incentive mechanism is installed to reduce controllable OPEX whereby any year on year reduction is shared 50/50 among the future tariffs and the TSO”).			
Adjustment mechanisms for differences between forecasted or allowed <u>capital expenditures</u> and realised spend	None			
Treatment of capital expenditure deferrals	No distinction for deferred capital expenditure			
Other revenue adjustment or incentive mechanisms	No			
Regulatory reporting				
Requirement for and frequency of regulatory reporting	Annually and semi-annually			
Coverage of regulatory reports	Regulatory financial statements, financial submissions			
Purpose of regulatory reports	To identify how the TSO is performing relative to forecast outcomes and the reasons for differences. To allow consistent assessments over time of the TSO’s cost efficiency and productivity, so informing future regulatory decisions. To allow the NRA to calculate the applicable adjustments to apply to allowed revenues in the following regulatory period because of differences between actual and forecast outcomes in the current period. To assess reasonableness of expenditures.			
Requirement for reconciliation with audited financial statements	Yes			
Key information sources				
- *NRA site: https://www.creg.be/*				

16.1.2 Bulgaria

Bulgaria

Regulatory, market and policy framework		
Regulator	Energy and Water Regulatory Commission (EWRC)	
TSO(s)	Bulgartransgaz EAD	
Customer mix	Residential/commercial	16%
	Large industrial	54%
	Power generation	30%
Ratio of transit to national flows	4.15 to 4.99	
Network age and length	Pipeline length	2,756 km
	Original operation	1973
Regulatory governance and process		
Entity that establishes the methodology and sets allowed/target revenues	EWRC (NRA)	
Length of revenue setting process	4 months	
Parties that can appeal NRA-determined revenues	TSO, transmission system users	
Type of appeal that is allowed	Limited merits/full merits review	
Overall framework for setting allowed revenues		
Type of regulation	Revenue cap	
Approach to assembling the cost base	Building block	
Duration of regulatory period	3 years	
Determining and setting operating expenditures		
Cost categories partially or fully passed through	Full pass-through items: taxes and duties, technical gas losses	
Methods and approaches to assessing and setting opex allowances	Bottom-up assessment Predictive modelling	
Inclusion of efficiency or productivity improvements	Yes	
Efficiency factors used in most recent regulatory period	0.6% per year	
Treatment of gas shrinkage	Pass-through cost	
Determining and setting capital expenditures		
Methods and approaches to assessing and setting allowances	Bottom-up assessment, detailed project/programme reviews, business case analysis (for larger projects)	
Use of uncertainty mechanisms	No	

Bulgaria

Inclusion of efficiency or productivity improvements	No	
Efficiency factors used in most recent regulatory period	N/A	
Use of ex post reviews before rolling capital expenditure or assets into the RAB	Yes - review both need and cost of investments	
Use of tendering for large system expansions	Yes - required for all expansions	
Regulatory asset base (RAB)		
Method used for setting the opening asset value (at the time of establishing the new regulatory framework)	Historical cost of the assets as per the TSO's statutory accounts at the time	
Depreciation of closing asset value as a single asset or as separate asset categories	Separate asset categories	
Revaluation of the RAB	No (there seem to have been some periodic revaluations since the original setting of the asset base, but this has not been confirmed by the NRA)	
Major assets included in the RAB	Pipelines, gas receiving stations, compressor stations, control stations, metering stations, SCADA stations and systems, linepack, metering and regulation stations at the interface with the distribution network	
Inclusion and treatment of linepack	Two categories of linepack: 90% linepack is treated as fixed (non-depreciating), 10% treated as a depreciating asset (and therefore has a declining value)	
Inclusion and treatment of working capital	Yes - '45-day approach'	
Timing of rolling investments into the RAB	When a capital project/programme is commissioned	
Depreciation		
Method	Straight-line	
Asset lives (for major asset groupings)	Pipelines	35 years
	Compressors	15 years
	Controllers/metering stations	15 years
	SCADA, telecoms	-
Cost of capital and financeability		
WACC method	Pre-tax, nominal WACC	
WACC value set in the two most recent regulatory periods	***Previous regulatory period***	***Current regulatory period***
	6.29%	8.14% (pre-tax)
WACC premium for specific investments or risks	No	
Primary (or only) methodology for setting the cost of equity	Capital Asset Pricing Model (CAPM)	
Method for setting the risk-free rate (RFR)	12-month average of 10-year Bulgarian government bonds	
Method for setting the equity or market risk	Historical data reflecting actual investment returns over time	

Bulgaria

<table>
<tr><td>premium (MRP/ERP)</td><td>(Dimson, Marsh and Staunton)
The estimate of the MRP is added to the RFR to estimate the total market return
Set using geometric average</td></tr>
<tr><td>Method for establishing the equity beta</td><td>By reference to regulatory precedents elsewhere</td></tr>
<tr><td>WACC parameters
(RP = Regulatory Period
CoE = Cost of Equity)</td><td>
<table>
<tr><td></td><td>RFR</td><td>MRP</td><td>Equity beta</td><td>Asset beta</td><td>CoE</td></tr>
<tr><td>Prev. RP</td><td></td><td></td><td></td><td></td><td>5.00%</td></tr>
<tr><td>Current RP</td><td>2.71%</td><td>5.69%</td><td>1.08</td><td>0.63</td><td>7.33%[67]</td></tr>
</table>
</td></tr>
<tr><td>Method for setting the cost of debt</td><td>Set ex ante using observed yields of ‘comparator companies’ using data from other Bulgarian companies and Central Bank data. Bond maturities chosen on an ad hoc, case-by-case basis.</td></tr>
<tr><td>Inclusion of debt issuance costs</td><td>Yes</td></tr>
<tr><td>Cost of debt parameters</td><td>
<table>
<tr><td></td><td>Debt premium (if relevant)</td><td>Cost of debt (net of issuance costs)</td><td>Debt issuance costs (if relevant)</td></tr>
<tr><td>Previous regulatory period</td><td></td><td>4.225%</td><td>-</td></tr>
<tr><td>Current regulatory period</td><td>N/A: 100% equity</td><td>N/A: 100% equity</td><td>N/A: 100% equity</td></tr>
</table>
</td></tr>
<tr><td>Gearing approach</td><td>Actual</td></tr>
<tr><td>Gearing level</td><td>
<table>
<tr><td>Previous regulatory period</td><td>n/a</td></tr>
<tr><td>Current regulatory period</td><td>0%</td></tr>
</table>
</td></tr>
<tr><td>Financeability assessment</td><td></td></tr>
<tr><td colspan="2">Other regulatory mechanisms (revenue adjustments and incentives)</td></tr>
<tr><td>Treatment of accumulated over or under-recoveries of revenues</td><td>Adjusted between regulatory periods</td></tr>
<tr><td>Adjustment mechanisms for differences between forecasted or allowed <u>operating expenditures</u> and realised spend</td><td>No adjustments, the allowances are treated as a ‘pure cap’ so that the business keeps the benefit of underspends and incurs the cost of overspends for the duration of the regulatory period</td></tr>
<tr><td>Adjustment mechanisms for differences between forecasted or allowed <u>capital expenditures</u> and realised spend</td><td>No adjustments, the allowances are treated as a ‘pure cap’ so that the business keeps the benefit of underspends and incurs the cost of overspends for the duration of the regulatory period</td></tr>
<tr><td>Treatment of capital expenditure deferrals</td><td>No differentiation made or separate treatment</td></tr>
<tr><td>Other revenue adjustment or incentive mechanisms</td><td>No</td></tr>
</table>

[67] We note that this CoE is not consistent with the stated RFR, MRP and Equity beta. Based on the stated parameters, the CoE = 8.86% in after-tax terms and 9.84% in pre-tax terms (with a corporate tax rate of 10%).

Bulgaria

Regulatory reporting	
Requirement for and frequency of regulatory reporting	Annually
Coverage of regulatory reports	Regulatory financial statements, financial submissions, physical submissions
Purpose of regulatory reports	To identify how the TSO is performing relative to forecast outcomes and the reasons for differences. To allow consistent assessments over time of the TSO's cost efficiency and productivity, so informing future regulatory decisions. To allow the NRA to calculate the applicable adjustments to apply to allowed revenues in the following regulatory period because of differences between actual and forecast outcomes in the current period.
Requirement for reconciliation with audited financial statements	Yes

Key information sources

- *NRA site*: http://www.dker.bg/en/home.html
- *Methodology*: https://www.bulgartransgaz.bg/en/pages/prozrachnost-tarifi-132.html.

16.1.3 Czech Republic

Czech Republic

Regulatory, market and policy framework		
Regulator	Energy Regulatory Office	
TSO(s)	NET4GAS, s. r. o.	
Customer mix	Residential	29%
	Commercial + Industrial	66%
	Power generation	5%
Ratio of transit to national flows	3:1 (2016)	
Network age and length	Pipeline length	3,821 km
	Original operation	1967
Regulatory governance and process		
Entity that establishes the methodology and sets allowed/target revenues	Energy Regulatory Office (NRA)	
Length of revenue setting process	16 months	
Parties that can appeal NRA-determined revenues	TSO, transmission system users	
Type of appeal that is allowed	Limited merits/full merits/procedural review	
Overall framework for setting allowed revenues		
Type of regulation	Price cap (for international transit) Revenue cap (for national transmission)	
Approach to assembling the cost base	Building block (for national transmission)	
Duration of regulatory period	5 years	
Determining and setting operating expenditures		
Cost categories partially or fully passed through	None	
Methods and approaches to assessing and setting opex allowances	Cost base – based on average of actual values of (economically justifiable) costs of previous two years. This cost base is then adjusted by escalation and efficiency factors for the current year. Extraordinary, one-off costs and costs not authorised by the NRA are excluded from the OPEX base. Extraordinary costs can be allowed *ex-post* on an individual basis. No adjustments are made for changes in the real prices of input costs.	
Inclusion of efficiency or productivity improvements	Yes	
Efficiency factors used in most recent regulatory period	Efficiency factor ('X factor') methodology was originally set before 2009 through international benchmarks of efficiency and realised efficiency savings in the previous regulatory period. For the 2016-20 regulatory period, the efficiency factor was set at approximately half the value of the previous regulatory period (2010-15) through TSO-DSO negotiations.	

Czech Republic

	▪ The annual X factor for third regulatory period (2010 – 2015) was 2.031% ▪ The annual X factor for fourth regulatory period (2016 – 2020) is 1.0101%.	
Treatment of gas shrinkage	For fuel gas (consumed in compressors), an ex-ante allowance is set (with no correction for realised volumes). The assumed consumption volume is based on historical consumption levels. Unaccounted for gas is treated as pass-through and included in allowed revenues (for national transmission)	
Determining and setting capital expenditures		
Methods and approaches to assessing and setting allowances	Bottom-up assessment	
Use of uncertainty mechanisms	N/A	
Inclusion of efficiency or productivity improvements	No	
Efficiency factors used in most recent regulatory period	N/A	
Use of ex post reviews before rolling capital expenditure or assets into the RAB	Yes	
Use of tendering for large system expansions	Yes	
Regulatory asset base (RAB)		
Method used for setting the opening asset value (at the time of establishing the new regulatory framework)	RAB was set at a level that ensured the prevailing level of profitability	
Depreciation of closing asset value as a single asset or as separate asset categories	Assets are depreciated individually	
Revaluation of the RAB	No	
Major assets included in the RAB	Pipelines, gas receiving stations, compressor stations, metering stations, SCADA stations and systems, metering and regulation stations at the interface with the distribution network	
Inclusion and treatment of linepack	Not included	
Inclusion and treatment of working capital	Not included	
Timing of rolling investments into the RAB	When a capital project/programme is commissioned. The value is not grossed up to account for financing costs.	
Depreciation		
Method	Straight-line	
Asset lives (for major asset groupings)	Pipelines	40 years
	Compressors	20 years
	Controllers/metering stations	10 years
	SCADA, telecoms	10 years

Czech Republic

Cost of capital and financeability		
WACC method	Pre-tax, nominal WACC	
WACC value set in the two most recent regulatory periods	***Previous regulatory period***	***Current regulatory period***
	6.105%	7.940%
WACC premium for specific investments or risks	No	
Primary (or only) methodology for setting the cost of equity	Capital Asset Pricing Model (CAPM)	
Method for setting the risk-free rate (RFR)	'Floating' RFR for every year based on the 12-month median of 10-year Czech government bond yields	
Method for setting the equity or market risk premium (MRP/ERP)	US market data from 1920 – average yield from stock market Estimate underlying MRP and add to the RFR to estimate total market returns MRP calculated using an arithmetic average	
Method for establishing the equity beta	By calculation, using publicly-traded European energy companies (versus the national capital markets in which the selected companies operate) over the period 2004-2014	

WACC parameters *(RP = Regulatory Period* *CoE = Cost of Equity)*		***RFR***	***MRP***	***Equity beta***	***Asset beta***	***CoE***
	Prev. RP (2014 only)	2.30%	5.85%	0.472	0.35	5.06%
	Current RP	3.82%	5.00%	0.801	0.5321	7.82%

Method for setting the cost of debt	Set *ex ante* as the risk-free rate plus a debt premium. Calculate RFR using Czech government bonds and the debt premium (credit risk margin) using the Euro Benchmark Yield curve (10-year risk-free rate of return in EUR), Euro corporate bonds, and Euro industrial bonds. Use bond maturities of 10 years over the past 10 years.
Inclusion of debt issuance costs	No

Cost of debt parameters		***Debt premium (if relevant)***	***Cost of debt (net of issuance costs)***	***Debt issuance costs (if relevant)***
	Previous regulatory period (2014 only)	1.38%	3.68%	N/A
	Current regulatory period	1.38%	5.19%	N/A

Gearing approach	Notional, derived from the D/E ratio of publicly traded European energy companies	
Gearing level	***Previous regulatory period***	30%

Czech Republic

	Current regulatory period	38%
Financeability assessment	No	
Other regulatory mechanisms (revenue adjustments and incentives)		
Treatment of accumulated over or under-recoveries of revenues	Adjusted within regulatory periods. Under/over recoveries of allowed revenues (correction factors) are adjusted annually (with a lag). Under/over recoveries in the last year of a regulatory period are included in the first or second year of the next regulatory period. The Production Price Index (PPI) or Consumer Price Index (CPI) is used for the time value of money. The NRA stated that adjustments consist of partial correction factors, where PPI is used for some elements and CPI for others, which suggests that adjustments other than just for the revenue cap (ie volume/capacity deviations) are made	
Adjustment mechanisms for differences between forecasted or allowed <u>operating expenditures</u> and realised spend	No	
Adjustment mechanisms for differences between forecasted or allowed <u>capital expenditures</u> and realised spend	No	
Treatment of capital expenditure deferrals	No	
Other revenue adjustment or incentive mechanisms	No	
Regulatory reporting		
Requirement for and frequency of regulatory reporting	Annually	
Coverage of regulatory reports	Regulatory financial statements, financial submissions, physical submissions	
Purpose of regulatory reports	To identify how the TSO is performing relative to forecast outcomes and the reasons for differences. To allow consistent assessments over time of the TSO's cost efficiency and productivity, so informing future regulatory decisions. To allow the NRA to calculate the applicable adjustments to apply to allowed revenues in the following regulatory period because of differences between actual and forecast outcomes in the current period.	
Requirement for reconciliation with audited financial statements	Yes	
Key information sources		
- *NRA site:* https://www.eru.cz/en/o-uradu - *Methodology:* http://www.eru.cz/documents/10540/3550177/Zasady-cenove-regulace-IV-RO-prodlouzene-do-2020.pdf		

16.1.4 Germany

Germany		
Regulatory, market and policy framework		
Regulator	Federal Network Agency for Electricity, Gas, Telecommunications, Post and Railway (BNETZA)	
TSO(s)	**Entry-exit-zone NCG**: Open Grid Europe, Thyssengas, bayernets, terranets, GRTgaz, Fluxys TENP **Entry-exit-zone Gaspool**: Gascade, Ontras, Gasunie, Jordgas, Nowega, GTG Nord, Lubmin Brandov Gastransport, OPAL, Fluxys Deutschland, NEL Gastransport	
Customer mix[68]	Residential/commercial	46%
	Large industrial	38%
	Power generation	13%
	Other	2%
Ratio of transit to national flows	Data not readily available	
Network age and length	Pipeline length	~37,000 km (summing up data provided by individual TSOs)
	Original operation (of network used today)	Mostly post-WWII (~1948)
Regulatory governance and process		
Entity that establishes the methodology and sets allowed/target revenues	Methodology developed by BNETZA (NRA) and the Ministry for Economic Affairs Approved by Parliament The NRA, Ministry for Economic Affairs, or the Government can initiate changes to the methodology	
Length of revenue setting process	Not standard, depends on the quality of TSO submissions (For the 3rd regulatory period from 2018-2022, the entire process took 2.5 years)	
Parties that can appeal NRA-determined revenues	TSOs	
Type of appeal that is allowed	Limited merits / full merits / procedural review	
Overall framework for setting allowed revenues		
Type of regulation	Revenue cap	
Approach to assembling the cost base	TOTEX (although CAPEX and OPEX are also assessed separately)	
Duration of regulatory period	5 years	

68 Data is for 2016 and was provided by BDEW (German Association for Water and Energy Industries).

Germany

Determining and setting operating expenditures	
Cost categories partially or fully passed through	‘Permanently non-controllable costs’ (which cannot be influenced by TSOs): ▪ concession fees ▪ operating taxes ▪ necessary use of upstream network levels ▪ (approved) ‘investment measures’ (see below) ▪ collective agreements on non-wage costs and fringe benefits, provided these were signed before 31 December 2016 ▪ statutory works council and staff council activities ▪ vocational training, day-care centres for children of staff in the network business ▪ specific research and development ▪ the amortisation of contributions to installation costs ▪ cross-border cost allocations ‘Volatile costs’ (that can be influenced by TSOs but vary widely): ▪ fuel costs (for compressor stations) ▪ costs regarding flow commitments
Methods and approaches to assessing and setting opex allowances	Costs are set using a reference or base year and a number of methodologies are employed to calculate costs for this year: bottom-up assessments, top-down assessments, TOTEX approach, benchmarking, and trend analysis (for detecting trends in OPEX)
Inclusion of efficiency or productivity improvements	Yes (factored in at TOTEX-level)
Efficiency factors used in most recent regulatory period	Annual productivity factor of 0.49 % (TOTEX-level) + TSO- individual efficiency factors depending on the efficiency of the individual TSO (result of efficiency benchmark). Efficiency values: terranets: 85,19 %, bayernets: 95,94, jordgas: 96,25, all other TSOs: 100% [not all values are final values]. Inefficiency (100% - TSO individual value) to be reduced within the regulatory period of 5 years
Treatment of gas shrinkage	Gas used in compressor stations is considered a ‘volatile cost’ (see above), which is treated as pass-through (note that the costs of the reference year are included in the efficiency benchmark)
Determining and setting capital expenditures	
Methods and approaches to assessing and setting allowances	Costs are set using a reference or base year and a number of methodologies are employed to calculate costs for this year: bottom-up assessments, top-down assessments, TOTEX approach, and benchmarking
Use of uncertainty mechanisms	The German system uses a mechanism called “investment measures” to account for new investments undertaken during the regulatory period. The basic assumption of the revenue cap regulation is that there are no major network expansions nor ‘restructuring’ during the regulatory period. Maintenance and reinvesting in existing

Germany	
	infrastructure are covered by the assessed/examined costs of the base year and thus in the initial revenue cap. However, costs for major expansions and, under specific conditions, for ‘restructuring’ are not covered by initial revenue caps. “Investment measures” add these costs to the initially set revenue cap. These costs are added to the revenue cap as “permanently non-controllable costs”. Investment measures are thus a cost-plus element.
Inclusion of efficiency or productivity improvements	Yes (factored in at TOTEX-level) + TSO- individual efficiency factors depending on the efficiency of the individual TSO (result of efficiency benchmark). Efficiency values: terranets: 85,19 %, bayernets: 95,94, jordgas: 96,25, all other TSOs: 100% [not all values are final values]. Inefficiency (100% - TSO individual value) to be reduced within the regulatory period of 5 years
Efficiency factors used in most recent regulatory period	Annual productivity factor of 0.49 % (TOTEX-level)
Use of ex post reviews before rolling capital expenditure or assets into the RAB	No
Use of tendering for large system expansions	Possibility exists, but has not occurred in practice
Regulatory asset base (RAB)	
Method used for setting the opening asset value (at the time of establishing the new regulatory framework)	The historical cost of the assets as per the TSO’s statutory accounts at the time. The German regulatory system distinguishes between old assets (capitalised before 2006, the year that regulation commenced) and new assets (capitalised in and after 2006). These are valued and depreciated differently (see below)
Depreciation of closing asset value as a single asset or as separate asset categories	Assets depreciated individually. New assets (2006 onwards) are depreciated based on historical costs. The share of old assets (pre-2006) financed by debt (minimum 60%) is depreciated based on historical costs. The share of old assets financed by equity (up to a maximum of 40%) is depreciated based on the assets´ replacement values. To calculate these replacement values, historical costs are inflated using price indices
Revaluation of the RAB	No
Major assets included in the RAB	Pipelines, gas receiving stations, compressor stations, control stations, metering stations, gas storage assets (TSOs may operate storage if it is solely used for the secure operation of the network and is not used for any other purpose, eg trading), meter and regulation stations at the interface with the distribution network, large consumer connection assets
Inclusion and treatment of linepack	Linepack is in most cases capitalised with the pipeline. The same depreciation period is used as for the pipeline assets
Inclusion and treatment of working capital	Yes, working capital is included. **For receivables**: the average time difference between billing and when revenue is collected, provided receivables are

Germany

<table>
<tr><td></td><td colspan="6">efficiently managed (10-15 days)
Cash is included if a TSO can prove that it is necessary using a cash flow calculation
Short-term liabilities are also taken into consideration</td></tr>
<tr><td>***Timing of rolling investments into the RAB***</td><td colspan="6">At the time of construction</td></tr>
<tr><td colspan="7">**Depreciation**</td></tr>
<tr><td>***Method***</td><td colspan="6">Straight-line</td></tr>
<tr><td rowspan="4">***Asset lives (for major asset groupings)***</td><td colspan="3">Pipelines</td><td colspan="3">45-65 years</td></tr>
<tr><td colspan="3">Compressors</td><td colspan="3">15-30 years</td></tr>
<tr><td colspan="3">Controllers/metering stations</td><td colspan="3">45 years</td></tr>
<tr><td colspan="3">SCADA, telecoms</td><td colspan="3">15-20 years</td></tr>
<tr><td colspan="7">**Cost of capital and financeability**</td></tr>
<tr><td>***WACC method***</td><td colspan="6">WACC not set
Cost of equity and cost of debt are treated separately</td></tr>
<tr><td rowspan="2">***WACC value set in the two most recent regulatory periods***</td><td colspan="3">***Previous regulatory period***</td><td colspan="3">***Current regulatory period***</td></tr>
<tr><td colspan="3">N/A</td><td colspan="3">N/A</td></tr>
<tr><td>***WACC premium for specific investments or risks***</td><td colspan="6">N/A</td></tr>
<tr><td>***Primary (or only) methodology for setting the cost of equity***</td><td colspan="6">Capital Asset Pricing Model (CAPM)</td></tr>
<tr><td>***Method for setting the risk-free rate (RFR)***</td><td colspan="6">Arithmetic mean of the current yield of fixed-interest securities of German issuers published by the German Central Bank (Deutsche Bundesbank) for the last ten calendar years</td></tr>
<tr><td>***Method for setting the equity or market risk premium (MRP/ERP)***</td><td colspan="6">Credit Suisse Global Investment Returns Sourcebook 2016 (Dimson, Marsh, Staunton), data of 23 countries, 1900-2015</td></tr>
<tr><td>***Method for establishing the equity beta***</td><td colspan="6">Apply Modigliani-Miller theorem (using a gearing ratio of 60%) and take into account taxes to calculate the equity beta based on the asset beta.
Use estimation periods of 1-year, 3-years, and 5-years.
Use daily observations.
Refer to risk factors calculated for energy companies across Europe.</td></tr>
<tr><td rowspan="2">***WACC parameters***
(RP = Regulatory Period
CoE = Cost of Equity)</td><td></td><td>***RFR***</td><td>***MRP***</td><td>***Equity beta***[69]</td><td>***Asset beta***</td><td>***CoE (post-tax)***</td></tr>
<tr><td>***Prev. RP***</td><td>3.80%</td><td>4.40%</td><td>0.66</td><td>0.32</td><td>New assets: 7.39%
Old assets: 5.83%</td></tr>
</table>

[69] Assumes 60% gearing.

Germany

	Current RP	2.49%	3.80%	0.83	0.4025	New assets: 5.64% Old assets: 4.18%
Method for setting the cost of debt	Set *ex ante*, considering the interest payments for debt capital that the TSO paid in the base year according to its financial statement (provided these interest payments are considered 'typical')					
Inclusion of debt issuance costs	Yes					
Cost of debt parameters		***Debt premium (if relevant)***	***Cost of debt (net of issuance costs)***	***Debt issuance costs (if relevant)***		
	Previous regulatory period	N/A	N/A	N/A		
	Current regulatory period	N/A	N/A	N/A		
Gearing approach	Notional The equity ratio is capped at 40%. The remaining capital is debt or capital which is available without interest. To the extent the equity exceeds 40%, the excess portion is remunerated using an interest rate calculated as the arithmetic mean of the yields on debt securities outstanding issued by residents (public debt securities, corporate bonds (excluding non-profit institutions at banks), mortgage bonds). These yields are published by the German Central Bank (Deutsche Bundesbank) as arithmetic means for the last 10 calendar years.					
Gearing level	***Previous regulatory period***	Capped at 60% (based on equity cap of 40%)				
	Current regulatory period	Capped at 60% (based on equity cap of 40%)				
Financeability assessment	No					
Other regulatory mechanisms (revenue adjustments and incentives)						
Treatment of accumulated over or under-recoveries of revenues	Independent of the regulatory period: The difference between revenue allowed and revenue generated by network operators in light of actual consumption volumes and the difference between changes in (some) volatile and some permanently non-controllable costs set based on planned values and actually incurred is entered annually in the regulatory account. The differences entered are to carry interest at the level of the average amount committed in the particular calendar year (average current yield, for the last ten full calendar years, of fixed interest securities of domestic issuers as published by the Deutsche Bundesbank). The average amount committed is					

Germany	
	obtained from the average of the amount at the beginning of the year and the final balance at the end of the year. The balance of the regulatory account for the last completed calendar year is to be reconciled as an annuity over the three years subsequent to the year when the balance is established (e.g. over- or under- recoveries of the year 2017 are reconciled in the years 2019-2021, balance is established in 2018)
Adjustment mechanisms for differences between forecasted or allowed <u>operating expenditures</u> and realised spend	No adjustments for controllable costs (non-controllable or volatile costs are adjusted via the regulatory account as explained above)
Adjustment mechanisms for differences between forecasted or allowed <u>capital expenditures</u> and realised spend	No adjustments for controllable costs (non-controllable or volatile costs are adjusted via the regulatory account as explained above)
Treatment of capital expenditure deferrals	No specific treatment
Other revenue adjustment or incentive mechanisms	No
Regulatory reporting	
Requirement for and frequency of regulatory reporting	Annually
Coverage of regulatory reports	Regulatory financial statements ('testified activity reports')
Purpose of regulatory reports	To identify how the TSO is performing relative to forecast outcomes and the reasons for differences. This is especially relevant to determine the deviation of actual/ realised revenues from forecasted /assumed revenues. 'Activity reports' are also used to understand the development of expenses/costs over several years in order to identify 'extraordinary' costs ' in the base year (which is used for setting allowances for the subsequent regulatory period). For the reference/base year, TSOs have to submit an additional report which contains additional information and explanations.
Requirement for reconciliation with audited financial statements	Yes
Key information sources	
- *NRA site:* https://www.bundesnetzagentur.de/EN/Home/home_node.html	

16.1.5 Croatia

Croatia

Regulatory, market and policy framework		
Regulator	Croatian Energy Regulatory Agency (HERA)	
TSO(s)	Plinacro Ltd	
Customer mix	Residential/commercial	42.8%
	Large industrial	35.7%
	Power generation	21.4%
Ratio of transit to national flows	0 (no transit)	
Network age and length	Pipeline length	2,693 km
	Original operation	1956
Regulatory governance and process		
Entity that establishes the methodology and sets allowed/target revenues	HERA (NRA)	
Length of revenue setting process	4-6 months	
Parties that can appeal NRA-determined revenues	TSO	
Type of appeal that is allowed	Full merits review	
Overall framework for setting allowed revenues		
Type of regulation	Revenue cap	
Approach to assembling the cost base	Building block	
Duration of regulatory period	5 years	
Determining and setting operating expenditures		
Cost categories partially or fully passed through	None	
Methods and approaches to assessing and setting opex allowances	Bottom-up assessment, top-down assessment In the first step, the allowed base OPEX for the year T-2 is determined. Then OPEX is projected for each year of the 5-year regulatory period with the formula: $OPEX_T = OPEX_{T-1}$ x (1 + CPI - X) The incentive method applied is a profit-sharing mechanism. At the end of the regulatory period, the base OPEX for the following regulatory period is defined so that the system operator retains 50% of the realised savings from the base year, but any overspend is not imposed on customers.	
Inclusion of efficiency or productivity improvements	Efficiency factor (X) partially based on the results of CEER's 'e2Gas benchmarking'[70]. HERA has applied a more conservative efficiency factor than the e2Gas benchmarking results.	
Efficiency factors used in most recent	1% per year	

[70] PROJECT E2GAS, Benchmarking European Gas Transmission System Operators, SUMICSID and Swiss Economics, 2 June 2016.

Croatia

regulatory period		
Treatment of gas shrinkage	For revenue setting purposes, there is an assumed amount of gas shrinkage equal to 0.3% of total gas volumes (as set by HERA) and which is valued at the purchase cost of gas. For losses above this, there is no further remuneration of the TSO.	
Determining and setting capital expenditures		
Methods and approaches to assessing and setting allowances	Bottom-up assessment, detailed project / programme reviews. Planned investments entailing the construction of new pipelines and gas stations are analysed using hydraulic simulations of the gas transmission system, taking into account demand forecasts and available network capacity.	
Use of uncertainty mechanisms	No	
Inclusion of efficiency or productivity improvements	No	
Efficiency factors used in most recent regulatory period	N/A	
Use of ex post reviews before rolling capital expenditure or assets into the RAB	Yes	
Use of tendering for large system expansions	Yes	
Regulatory asset base (RAB)		
Method used for setting the opening asset value (at the time of establishing the new regulatory framework)	Revaluation of assets was done in 2001 as part of the unbundling process from VIU (INA Ltd) based on a 'fair value' methodology	
Depreciation of closing asset value as a single asset or as separate asset categories	Assets depreciated individually	
Revaluation of the RAB	No	
Major assets included in the RAB	Pipelines, gas receiving stations, control stations, metering stations, SCADA stations and systems, linepack, gas storage assets, metering and regulation stations at the interface with the distribution network, large consumer connection assets	
Inclusion and treatment of linepack	Set as a fixed quantity valued at purchasing cost (subject to HERA justifiability analysis)	
Inclusion and treatment of working capital	No	
Timing of rolling investments into the RAB	When a capital project/programme is commissioned. The value is not grossed up to account for financing costs.	
Depreciation		
Method	Straight-line	
Asset lives (for major asset groupings)	Pipelines	35 years
	Compressors	35 years
	Controllers/metering stations	35 years
	SCADA, telecoms	10-20 years

Croatia

Cost of capital and financeability	
WACC method	Pre-tax, nominal WACC

WACC value set in the two most recent regulatory periods	***Previous regulatory period***	***Current regulatory period***
	5.76%	5.22%

WACC premium for specific investments or risks	No
Primary (or only) methodology for setting the cost of equity	Capital Asset Pricing Model (CAPM)
Method for setting the risk-free rate (RFR)	Average nominal interest rate of the most recent ten-year domestic or international bond issued by the Republic of Croatia.
Method for setting the equity or market risk premium (MRP/ERP)	Market risk premium is determined based on the expected rate of return on a diversified market portfolio in the Republic of Croatia. Currently the MRP is benchmarked against that which is used for other regulated utilities in Croatia. May eventually use Zagreb Stock Exchange data. Add estimated MRP to RFR to estimate total market returns.
Method for establishing the equity beta	By reference to regulatory precedents elsewhere

WACC parameters *(RP = Regulatory Period CoE = Cost of Equity)*		***RFR***	***MRP***	***Equity beta***	***Asset beta***	***CoE***
	Prev. RP	3.00%	5.80%	0.54	0.30	6.13%
	Current RP	2.75%	4.80%	0.54	0.30	5.34%

Method for setting the cost of debt	The cost of debt is equal to the weighted average interest rate on the borrowings of the TSO. If the TSO does not use debt, the cost of debt (for the notional debt component) is set at the average bank interest rates for long-term HRK-indexed loans granted to companies in Croatia, and the average monthly interest rates in the last 12 months as listed in the Croatian National Bank's most recent 'monthly bulletin'.
Inclusion of debt issuance costs	No

Cost of debt parameters		***Debt premium (if relevant)***	***Cost of debt (net of issuance costs)***	***Debt issuance costs (if relevant)***
	Previous regulatory period		3.85%	
	Current regulatory period		3.92%	

Gearing approach	Notional	
Gearing level	***Previous regulatory period***	50

Croatia

	Current regulatory period	50	
Financeability assessment	No		
Other regulatory mechanisms (revenue adjustments and incentives)			
Treatment of accumulated over or under-recoveries of revenues	Over or under-recoveries are allocated to the next regulatory period, applying the allowed rate of return/WACC for the time value of money.		
Adjustment mechanisms for differences between forecasted or allowed operating expenditures and realised spend	Applied asymmetrically using a 50% sharing factor for underspends Base opex in each regulatory period is set using the outturn opex of the second last year of the regulatory period. This is then indexed for inflation using CPI and the TSO is also permitted to retain 50% of any savings in the base year compared to the previously set opex allowance (if the allowances are exceeded, the TSO bears the cost ie there is no sharing with network users)		
Adjustment mechanisms for differences between forecasted or allowed capital expenditures and realised spend	No adjustment mechanism is applied for capital expenditure		
Treatment of capital expenditure deferrals	The depreciation and allowed return on these investments is 'clawed back' 100%.		
Other revenue adjustment or incentive mechanisms	No		
Regulatory reporting			
Requirement for and frequency of regulatory reporting	Annually		
Coverage of regulatory reports	Regulatory financial statements, physical submissions		
Purpose of regulatory reports	To allow consistent assessments over time of the TSO's cost efficiency and productivity, so informing future regulatory decisions. To allow the NRA to calculate the applicable adjustments to apply to allowed revenues in the following regulatory period because of differences between actual and forecast outcomes in the current period.		
Requirement for reconciliation with audited financial statements	Yes		
Key information sources			
Provide links for: - *NRA site:* https://www.hera.hr/english/html/index.html - *Methodology:* https://www.hera.hr/en/docs/OG_2013_1892.pdf *(unofficial consolidated text)*			

16.1.6 Ireland

Republic of Ireland

Regulatory, market and policy framework		
Regulator	Commission for Regulation of Utilities, Ireland	
TSO(s)	Gas Networks Ireland	
Customer mix	Residential/commercial	13%
	Industrial/commercial	30%
	Power generation	57%
Ratio of transit to national flows	N/A	
Network age and length	Pipeline length	13 945 km
	Original operation	1976
Regulatory governance and process		
Entity that establishes the methodology and sets allowed/target revenues	Commission for Regulation of Utilities	
Length of revenue setting process	18 months	
Parties that can appeal NRA-determined revenues	TSO, Transmission Systems User	
Type of appeal that is allowed	Full merits review	
Overall framework for setting allowed revenues		
Type of regulation	Revenue cap	
Approach to assembling the cost base	Building block approach	
Duration of regulatory period	5 years	
Determining and setting operating expenditures		
Cost categories partially or fully passed through	▪ CRU levies ▪ CO_2 ▪ Rates (50% pass-through)	
Methods and approaches to assessing and setting opex allowances	A bottom-up and top-down assessment of the TSO's proposed opex allowance is carried out. CRU may, and often does, engage technical and/or economic consultants to support this process	
Inclusion of efficiency or productivity improvements	Yes, CRU use CPI-X but the productivity factor (labelled 'ongoing efficiency') is applied to opex costs only, at a total level. ie bottom up assessment then application of an ongoing efficiency challenge to set the overall opex allowance	
Efficiency factors used in most recent regulatory period	1% in current and last regulatory period	
Treatment of gas shrinkage	Full pass-through (and recovered from shippers, pro-rata based on throughput)	
Determining and setting capital expenditures		
Methods and approaches to assessing and setting allowances	A bottom-up assessment is conducted on the expected drivers of capex over the regulatory period. Technical and economic consultants may be engaged as needed and techniques used are dependent on need. Typically: business case analysis may	

Republic of Ireland

	be used to determine what goes into the allowed revenues for capital expenditure.	
Use of uncertainty mechanisms	Uncertainty mechanisms are used on an ad hoc basis. If the TSO goes over budget, but can justify and explain the increase, the increase is allowed but there is a small financing penalty applied (to encourage more accurate budgeting).	
Inclusion of efficiency or productivity improvements	No	
Efficiency factors used in most recent regulatory period	N/A	
Use of ex post reviews before rolling capital expenditure or assets into the RAB	Yes, with reviews of the investment needed and the cost.	
Use of tendering for large system expansions	Yes - As a public authority they are subject to the utilities procurement objective	
Regulatory asset base (RAB)		
Method used for setting the opening asset value (at the time of establishing the new regulatory framework)	The historical cost was indexed with inflation to calculate the indexed gross asset values. These were then depreciated to calculate the indexed net book value of the RAB.	
Depreciation of closing asset value as a single asset or as separate asset categories	Asset categories are depreciated individually	
Revaluation of the RAB	The RAB is not revalued. Increases occur with the approval of new capital expenditure which expands the asset base.	
Major assets included in the RAB	Pipelines, compressor stations, metering stations, metering and regulation stations at the interface with the distribution network, large customer connections assets	
Inclusion and treatment of linepack	Linepack is not included in the RAB	
Inclusion and treatment of working capital	Working capital is not included in the RAB	
Timing of rolling investments into the RAB	Assets are included in the RAB when they are commissioned. The value added includes financing costs that are based on a monthly cost agreed with the Treasury.	
Depreciation		
Method	Straight-line depreciation	
Asset lives (for major asset groupings)	Pipelines	50 years
	Compressors	25 years
	Controllers/metering stations	15 years
	SCADA, telecoms	-
Cost of capital and financeability		
WACC method	An allowed WACC is set in pre-tax terms based on the real cost of capital. The WACC is set at the start of the price control but a trigger mechanism is included to allow for adjustments based on annual reviews—the reviews determine if market conditions in Ireland have changed substantively.	
WACC value set in the two most recent regulatory periods	***Previous regulatory period***	***Current regulatory period***
	5.2- 8.2%	4.63%
WACC premium for specific investments or	No premium is allowed	

Republic of Ireland

<table>
<tr><td>risks</td><td></td></tr>
<tr><td>Primary (or only) methodology for setting the cost of equity</td><td>Capital Asset Pricing Model (CAPM)</td></tr>
<tr><td>Method for setting the risk-free rate (RFR)</td><td>Calculated on the historical yields of 10-year Eurozone Government Bonds</td></tr>
<tr><td>Method for setting the equity or market risk premium (MRP/ERP)</td><td>The market risk premium is established by assessing the precedents set by other regulatory bodies, in Ireland, Northern Ireland and Great Britain</td></tr>
<tr><td>Method for establishing the equity beta</td><td>Geometric mean</td></tr>
<tr><td>WACC parameters
(RP = Regulatory Period
CoE = Cost of Equity)</td><td>
<table>
<tr><th></th><th>RFR</th><th>MRP</th><th>Equity beta</th><th>Asset beta</th><th>CoE</th></tr>
<tr><td>Prev RP</td><td>3.5% – 5.5%</td><td>4.5% – 5.0%</td><td>0.78</td><td>0.35</td><td>6.9% – 9.2%</td></tr>
<tr><td>Current RP</td><td>1.9%</td><td>4.75%</td><td>0.93</td><td>0.42</td><td>6.32%</td></tr>
</table>
</td></tr>
<tr><td>Method for setting the cost of debt</td><td>Ex-ante allowance for debt. The allowance is based on a hypothetical entrant based on comparable companies and using other regulatory precedents, eg:
▪ Northern Ireland GD17 distribution control
▪ CMA Bristol Water
▪ Ofwat PR14
▪ ComReg
▪ Ofgem RIIO ED1
▪ CAR
▪ CC Northern Ireland Electricity</td></tr>
<tr><td>Inclusion of debt issuance costs</td><td>No</td></tr>
<tr><td>Cost of debt parameters</td><td>
<table>
<tr><th></th><th>Debt premium (if relevant)</th><th>Cost of debt (net of issuance costs)</th><th>Debt issuance costs (if relevant)</th></tr>
<tr><td>Previous regulatory period</td><td>Not in public domain</td><td>3.3-4.3%</td><td>n/a</td></tr>
<tr><td>Current regulatory period</td><td>1.0%</td><td>2.5%</td><td>n/a</td></tr>
</table>
</td></tr>
<tr><td>Gearing approach</td><td>Notional</td></tr>
<tr><td>Gearing level</td><td>
<table>
<tr><td>Previous regulatory period</td><td>55%</td></tr>
<tr><td>Current regulatory period</td><td>55%</td></tr>
</table>
</td></tr>
<tr><td>Financeability assessment</td><td>Various financeability test are completed. They include:
▪ the funds from operations (“FFO”) interest cover multiple;
▪ gearing;
▪ the ratio of FFO to net debt; and,
▪ the ratio of retained cash flow to net debt</td></tr>
</table>

Republic of Ireland	
Other regulatory mechanisms (revenue adjustments and incentives)	
Treatment of accumulated over or under-recoveries of revenues	Accumulated over and under-recoveries are adjusted (k factor adjustment) between years (and within periods if necessary). If the 'K factor' exceeds more than 5% of allowed revenues in the year in which the under or over recovery occurred, the K factor is spread over two years, with the excess over the 5% carried over to the second year rather than being recovered in the one year. The CRU also applies one other adjustment to K factors. Where the revenue recovered by the TSO is greater than 103% of the allowed revenue then the amount up to 103% attracts a penalty of Euribor plus 2% and anything above 103% attracts a penalty of Euribor plus 4% in period t-1. The rate in period t is Euribor plus 2% regardless of the amount of the over-recovery (that is, the system is asymmetrical, so that 2% is applied for all adjustments where revenue is below 100%).
Adjustment mechanisms for differences between forecasted or allowed operating expenditures and realised spend	No adjustment mechanism – the TSO bears in full any differences from the allowance, either over- or underspends, for opex that is not classified as pass-through. This historical review of operating expenditure is used to derive normalised or 'business as usual' costs that form the basis for proposed operating expenditure allowances for the next regulatory period.
Adjustment mechanisms for differences between forecasted or allowed capital expenditures and realised spend	Adjustments for capital expenditure are allowed. Allowed capital adjustments are carried forward using the allowed rate of return/WACC to account for the time value of money.
Treatment of capital expenditure deferrals	No distinction between deferrals made for efficiency and those outside the TSO's control. However, in the case of deferrals, the TSO is awarded a return at the WACC and the depreciation for 2.5 years (half of the regulatory period).
Other revenue adjustment or incentive mechanisms	Efficiency savings. Where the TSO comes under the cost for a project it receives 5 years return and 5 years depreciation on those savings. This is related to unit costs when possible so the TSO is not rewarded for doing less work but instead for reducing cost per unit
Regulatory reporting	
Requirement for and frequency of regulatory reporting	The TSO submits regulatory financial statements on an annual basis. This is in accordance with the transmission operator/owner licence. These statements are independently audited.
Coverage of regulatory reports	Not stated
Purpose of regulatory reports	Not stated
Requirement for reconciliation with audited financial statements	Not stated
Key information sources	
- *NRA :*https://www.cru.ie/ - *Methodology:* https://www.cru.ie/document_group/gas-networks-ireland-allowed-revenues-and-gas-transmission-tariffs/	

16.1.7 Luxembourg

Luxembourg

Regulatory, market and policy framework		
Regulator	Institut Luxembourgeois de Régulation	
TSO(s)	Creos Luxembourg S.A.	
Customer mix	Residential/commercial	62%
	Large industrial	29%
	Power generation	9%
Ratio of transit to national flows	0% (no transit)	
Network age and length	Pipeline length	282 km
	Original operation	1972
Regulatory governance and process		
Entity that establishes the methodology and sets allowed/target revenues	Institut Luxembourgeois de Régulation (NRA)	
Length of revenue setting process	4 -5 months	
Parties that can appeal NRA-determined revenues	The TSO and any other party that has a legitimate interest in bringing action against the decision	
Type of appeal that is allowed	A limited merits and procedural review	
Overall framework for setting allowed revenues		
Type of regulation	Revenue cap	
Approach to assembling the cost base	Building blocks approach	
Duration of regulatory period	4 years	
Determining and setting operating expenditures		
Cost categories partially or fully passed through	Full pass through of: ▪ Supplementary pensions before 2010, ▪ Salary indexation ▪ Taxes and levies ▪ Notary costs ▪ Losses ▪ Use of external networks ▪ Auxiliary services ▪ Preparatory studies ▪ Cost related to international cooperation ▪ Common project between TSO/DSOs with the aim to improve market functioning ▪ R&D	
Methods and approaches to assessing and setting opex allowances	Bottom-up assessments are used to set operational expenditure allowances	
Inclusion of efficiency or productivity improvements	Yes, calculated by the national statistics body	
Efficiency factors used in most recent	1%	

Luxembourg

regulatory period		
Treatment of gas shrinkage	Considered a pass-through cost, and considered to be gas consumed in TSO regulation stations	
Determining and setting capital expenditures		
Methods and approaches to assessing and setting allowances	Ex-ante capital expenditure reviews using a bottom-up assessment. The regulator may conduct detailed project reviews and cost benefit analysis on individual projects before including them in the allowed revenues (projects costing more than EUR 500,000 face additional scrutiny).	
Use of uncertainty mechanisms	No	
Inclusion of efficiency or productivity improvements	No	
Efficiency factors used in most recent regulatory period	N/A	
Use of ex post reviews before rolling capital expenditure or assets into the RAB	Yes, forecasted costs and realised costs are compared, as are planned and realised durations. Reviews focus on projects costing more than EUR 500,000 or projects with a cross-border impact	
Use of tendering for large system expansions	Yes, for all assets where the investment exceeds thresholds in national or European laws	
Regulatory asset base (RAB)		
Method used for setting the opening asset value (at the time of establishing the new regulatory framework)	Based on the historical cost of the assets ie the depreciated book value of the assets as per the TSO's statutory accounts	
Depreciation of closing asset value as a single asset or as separate asset categories	Asset categories are depreciated individually	
Revaluation of the RAB	No	
Major assets included in the RAB	Major assets include pipelines, gas receiving stations and buildings	
Inclusion and treatment of linepack	Not included	
Inclusion and treatment of working capital	Working capital is not included in the RAB	
Timing of rolling investments into the RAB	Investments are rolled into the RAB upon commissioning, except for 'large' projects (>€500k) and those with cross-border impact, where work-in progress is also remunerated (but penalties also apply for time delays)	
Depreciation		
Method	Straight-line	
Asset lives (for major asset groupings)	Pipelines	40 years
	Compressors	40 years
	Controllers/metering stations	40 years
	SCADA, telecoms	10 years
Cost of capital and financeability		
WACC method	Pre-tax nominal terms	

<table>
<tr><td colspan="7">Luxembourg</td></tr>
<tr><td rowspan="2">WACC value set in the two most recent regulatory periods</td><td colspan="3">Previous regulatory period</td><td colspan="3">Current regulatory period</td></tr>
<tr><td colspan="3">7.60%</td><td colspan="3">6.12%</td></tr>
<tr><td>WACC premium for specific investments or risks</td><td colspan="6">No specific premium</td></tr>
<tr><td>Primary (or only) methodology for setting the cost of equity</td><td colspan="6">Capital Asset Pricing Model (CAPM)</td></tr>
<tr><td>Method for setting the risk-free rate (RFR)</td><td colspan="6">Medium term view (3-5 years) on long term (10-year) interest rates for Luxembourg, published by ECB</td></tr>
<tr><td>Method for setting the equity or market risk premium (MRP/ERP)</td><td colspan="6">Historical data reflecting actual investment returns over time as reported in Dimson, Staunton and Marsh (2015) – world portfolio from 1900 onwards</td></tr>
<tr><td>Method for establishing the equity beta</td><td colspan="6">Established by reference to regulatory precedent elsewhere</td></tr>
<tr><td rowspan="3">WACC parameters
(RP = Regulatory Period
CoE = Cost of Equity)</td><td></td><td>RFR</td><td>MRP</td><td>Equity beta</td><td>Asset beta</td><td>CoE (after tax)</td></tr>
<tr><td>Prev. RP</td><td>3.90%</td><td>4.6%</td><td>0.6954</td><td>0.41</td><td>7.10%</td></tr>
<tr><td>Current RP</td><td>2.15%</td><td>4.8%</td><td>0.7946</td><td>0.47</td><td>5.96%</td></tr>
<tr><td>Method for setting the cost of debt</td><td colspan="6">Ex-ante based on a midterm view of the cost of debt of comparator companies (using Bloomberg data). Specifically, debt spreads are examined for a set of international energy companies, over a 7-13 year time span</td></tr>
<tr><td>Inclusion of debt issuance costs</td><td colspan="6">No</td></tr>
<tr><td rowspan="3">Cost of debt parameters</td><td colspan="3"></td><td>Debt premium (if relevant)</td><td>Cost of debt (net of issuance costs)</td><td>Debt issuance costs (if relevant)</td></tr>
<tr><td colspan="3">Prev. RP</td><td>1.10%</td><td>5.0%</td><td>-</td></tr>
<tr><td colspan="3">Current RP</td><td>1.45%</td><td>3.60%</td><td>-</td></tr>
<tr><td>Gearing approach</td><td colspan="6">Notional</td></tr>
<tr><td rowspan="2">Gearing level</td><td colspan="3">Previous regulatory period</td><td colspan="3">50%</td></tr>
<tr><td colspan="3">Current regulatory period</td><td colspan="3">50%</td></tr>
<tr><td>Financeability assessment</td><td colspan="6">No separate financeability assessments</td></tr>
<tr><td colspan="7">Other regulatory mechanisms (revenue adjustments and incentives)</td></tr>
<tr><td>Treatment of accumulated over or under-recoveries of revenues</td><td colspan="6">Both under and over-recoveries (calculated annually) are carried forward into the next regulatory period. A short-term borrowing rate is applied to the adjustments</td></tr>
<tr><td>Adjustment mechanisms for differences between forecasted or allowed <u>operating expenditures</u> and realised spend</td><td colspan="6">None (underspends and overspends are retained/ incurred by the TSO only during the regulatory period)</td></tr>
<tr><td>Adjustment mechanisms for differences between forecasted or allowed <u>capital</u></td><td colspan="6">Adjustments are made and carried forward using the WACC. A symmetric sharing mechanism applies for over and</td></tr>
</table>

 **Luxembourg**	
expenditures ***and realised spend***	underspending with 30% going to the TSO.
Treatment of capital expenditure deferrals	The framework distinguishes between deferrals due to factors outside the TSO's control, which typically include: administrative decisions concerning permissions, additional environmental impact studies, issues to conclude agreements with landowners
Other revenue adjustment or incentive mechanisms	No
Regulatory reporting	
Requirement for and frequency of regulatory reporting	Yes, annually
Coverage of regulatory reports	Regulatory financial statements, financial submissions, physical submissions
Purpose of regulatory reports	To identify how the TSO is performing relative to forecast outcomes and the reasons for differences To allow consistent assessments over time of the TSO's cost efficiency and productivity, so informing future regulatory decisions To allow the NRA to calculate the applicable adjustments to apply to allowed revenues in the following regulatory period because of differences between actual and forecast outcomes in the current period
Requirement for reconciliation with audited financial statements	No
Key information sources	

16.1.8 Netherlands

Netherlands		
Regulatory, market and policy framework		
Regulator	Authority for Consumers and Markets	
TSO(s)	Gasunie Transport Services B.V.	
Customer mix	Residential/commercial	Data not available
	Large industrial	Data not available
	Power generation	Data not available
Ratio of transit to national flows	Approximately 33%	
Network age and length	Pipeline length	11,944 km
	Original operation	1946
Regulatory governance and process		
Entity that establishes the methodology and sets allowed/target revenues	NRA sets the methodology and the allowed revenues	
Length of revenue setting process	A total of approximately 18 months	
Parties that can appeal NRA-determined revenues	The TSO, representative organisations of transmission system users and any party that has a relevant individual interest in the decision	
Type of appeal that is allowed	In principle, the review is limited to areas that are appealed (limited merits review)	
Overall framework for setting allowed revenues		
Type of regulation	Revenue cap	
Approach to assembling the cost base	TOTEX approach	
Duration of regulatory period	5 years (although the NRA has the discretion to decide between three and five years)	
Determining and setting operating expenditures		
Cost categories partially or fully passed through	Any costs made during the regulatory period of 2017-2021 on either (i) nitrogen or (ii) electricity to produce nitrogen for the purpose of gas quality conversion are fully passed through if they are deemed efficient based on an *ex post* assessment. This is an exemption to the general rule that no costs are fully passed through. This exemption was made because these costs are (due to specific circumstances) difficult to estimate which results in a significant financial risk for the TSO for which the TSO is not compensated.	
Methods and approaches to assessing and setting opex allowances	A TOTEX approach is used and benchmarking (data envelopment analysis), while trend analysis is also used to examine expenditure over time taking into account inflation and efficiency	
Inclusion of efficiency or productivity improvements	Yes, covering both static (catch-up) efficiency and dynamic (frontier shift) efficiency	
Efficiency factors used in most recent regulatory period	The TSO allowed revenues are adjusted for catch-up efficiency by gradually decreasing during the regulatory period to a level deemed efficient (based on benchmarking/DEA analysis). The	

Netherlands	
	efficient costs were calculated by taking an average of the efficient costs given by the benchmark with the German TSOs, 83.6% of the estimated cost level, and the benchmark with 21 European TSOs, 86.6% of the estimated cost level. The NRA also assumed a frontier shift of 0.6%. (For the benchmark, this only includes the costs (opex and capex), insofar that they were included in the benchmark studies. The frontier shift is applied to all costs).
Treatment of gas shrinkage	Gas used by GTS is either measured (eg compression) or estimated (eg losses during construction works). The estimated/measured cost of gas used by GTS is part of the operational expenditure and not treated any differently from other opex. As a result, if all measurements and estimations are correct, there are no gas losses. Unaccounted for gas is the result of measurement errors, measurement uncertainty or estimation errors of all flows through the grid (not only gas used by GTS). Unaccounted for gas can result in both a gain or a loss for GTS. Such gains or losses are reconciled with the allowed revenue, so GTS does not gain or lose as a result of unaccounted for gas.
Determining and setting capital expenditures	
Methods and approaches to assessing and setting allowances	A TOTEX approach is used and benchmarking (data envelopment analysis). The NRA also analyses in general terms whether strategic planning practices, risk management techniques and asset management are sufficient, through assessment of the so-called quality- and capacity document (KCD). However, this procedural assessment is not used for assessing the efficiency of capital expenditure
Use of uncertainty mechanisms	No
Inclusion of efficiency or productivity improvements	Yes, covering both static (catch-up) efficiency and dynamic (frontier shift) efficiency
Efficiency factors used in most recent regulatory period	The TSO allowed revenues are adjusted for catch-up efficiency by gradually decreasing during the regulatory period to a level deemed efficient (based on benchmarking/DEA analysis). The efficient costs were calculated by taking an average of the efficient costs given by the benchmark with the German TSOs, 83.6% of the estimated cost level, and the benchmark with 21 European TSOs, 86.6% of the estimated cost level. The NRA also assumed a frontier shift of 0.6%. (For the benchmark, this only includes the costs (opex and capex), insofar that they were included in the benchmark studies. The frontier shift is applied to all costs).
Use of ex post reviews before rolling capital expenditure or assets into the RAB	No
Use of tendering for large system expansions	The NRA must determine whether the costs of the project are efficient, and a commitment to tendering is one way to determine that
Regulatory asset base (RAB)	
Method used for setting the opening asset value (at the time of establishing the new regulatory framework)	Indexed historical cost

Netherlands			
Depreciation of closing asset value as a single asset or as separate asset categories	Depreciated as separate categories		
Revaluation of the RAB	No		
Major assets included in the RAB	Pipelines, gas receiving stations, compressor stations, control stations, metering stations, SCADA stations and systems, linepack, metering and regulation stations at the interface with the distribution network, large consumer connection assets, gas quality conversion stations, nitrogen production stations, nitrogen, storage, nitrogen, LNG peak shaving installation, land, buildings, vehicles, equipment		
Inclusion and treatment of linepack	Linepack is included Amount: Variable amount depending on the rates of intakes and offtakes on the pipelines Price: Wholesale price index		
Inclusion and treatment of working capital	Working capital is not included		
Timing of rolling investments into the RAB	Upon commissioning and the value is grossed up using the allowed cost of capital		
Depreciation			
Method	Straight-line depreciation		
Asset lives (for major asset groupings)	Pipelines	55 years	
	Compressors	30 years	
	Controllers/metering stations	30 years	
	SCADA, telecoms	5 – 15 years	
Cost of capital and financeability			
WACC method	Pre-tax real		
WACC value set in the two most recent regulatory periods	***Previous regulatory period***	***Current regulatory period***	
	3.6%	The WACC varies by year and type of investment. The CoE is uniform throughout, but the RFR and CoD vary depending on the year and whether capex is for replacement/ refurbishment or expansion (as it takes into account embedded debt costs, if relevant). Eg, the WACC for replacement/ refurbishment investments (real, pre-tax) is set at 4.3% in 2016 and 3.0% in 2021. For expansion investments, it is set at 3.6% in 2016 and 3.0% in 2021	
WACC premium for specific investments or risks	No		
Primary (or only) methodology for setting the cost of equity	Capital Asset Pricing Model (CAPM) which is then cross checked with other studies that give predictions on the ERP.		

<table>
<tr><td colspan="2">
Netherlands</td></tr>
<tr><td>Method for setting the risk-free rate (RFR)</td><td>Determined by a 50/50 mix of Dutch and German 10-year government bonds over a reference period of three year</td></tr>
<tr><td>Method for setting the equity or market risk premium (MRP/ERP)</td><td>Based on historical data reflecting actual returns. The returns are sanity checked by forward looking data regarding investor expectations</td></tr>
<tr><td>Method for establishing the equity beta</td><td>The equity beta is calculated using the stock markets of European peers, the stock values of regulated peers estimated over a period of three years.</td></tr>
<tr><td>WACC parameters
(RP = Regulatory Period
CoE = Cost of Equity)</td><td><table>
<tr><th></th><th>RFR</th><th>MRP</th><th>Equity beta</th><th>Asset beta</th><th>CoE (nom.)</th></tr>
<tr><td>Prev. RP</td><td>2.50%</td><td>5.00%</td><td>0.61</td><td>0.35</td><td>5.60%</td></tr>
<tr><td>Current RP[71]</td><td>1.28%</td><td>5.05%</td><td>0.74</td><td>0.42</td><td>5.02%</td></tr>
</table></td></tr>
<tr><td>Method for setting the cost of debt</td><td>Ex ante calculation of debt costs using at trailing average of German and Dutch bonds over 10 years</td></tr>
<tr><td>Inclusion of debt issuance costs</td><td>Yes</td></tr>
<tr><td>Cost of debt parameters</td><td><table>
<tr><th></th><th>RFR</th><th>Debt premium (if relevant)</th><th>Cost of debt (net of issuance costs)</th><th>Debt issuance costs (if relevant)</th></tr>
<tr><td>Prev. RP</td><td>2.50%</td><td>1.20%</td><td>3.70%</td><td>0.15%</td></tr>
<tr><td>Current RP</td><td>1.28%/ 1.33%</td><td>0.76%/ 0.81%</td><td>2.04%/ 2.14%</td><td>0.15%</td></tr>
</table></td></tr>
<tr><td>Gearing approach</td><td>Notional gearing based on market information and comparison to peer utilities.</td></tr>
<tr><td>Gearing level</td><td><table>
<tr><td>Previous regulatory period</td><td>50%</td></tr>
<tr><td>Current regulatory period</td><td>50%</td></tr>
</table></td></tr>
<tr><td>Financeability assessment</td><td>N/A</td></tr>
<tr><td colspan="2">Other regulatory mechanisms (revenue adjustments and incentives)</td></tr>
<tr><td>Treatment of accumulated over or under-recoveries of revenues</td><td>Adjusted yearly to account for over and under recoveries. They are adjusted by the interest that the Dutch tax authority uses for overdue taxes to account for time delays between adjustments</td></tr>
<tr><td>Adjustment mechanisms for differences between forecasted or allowed <u>operating expenditures</u> and realised spend</td><td>None (except for nitrogen-related costs mentioned above in relation to pass-throughs)</td></tr>
<tr><td>Adjustment mechanisms for differences</td><td>None</td></tr>
</table>

[71] We note that the WACC varies by year and type of investment. The CoE is uniform throughout, but the RFR and CoD vary depending on the year and whether capex is for replacement/refurbishment or expansion (as it takes into account embedded debt costs, if relevant). Eg, the WACC for replacement/ refurbishment investments (real, pre-tax) is set at 4.3% in 2016 and 3.0% in 2021. For expansion investments, it is set at 3.6% in 2016 and 3.0% in 2021.

Netherlands	
between forecasted or allowed <u>capital expenditures</u> and realised spend	
Treatment of capital expenditure deferrals	The NRA does not distinguish between capital expenditure deferrals made for reasons of efficiency and those due to factors outside the TSO's control. There is no clawback. If the TSO can fulfil its statutory tasks while postponing or deferring capital expenditure agreed in the allowed revenue, the TSO increases its profits. As a result, the TSO is incentivised only to invest when necessary to fulfil its statutory tasks.
Other revenue adjustment or incentive mechanisms	No additional incentive mechanisms
Regulatory reporting	
Requirement for and frequency of regulatory reporting	Annual reporting is required
Coverage of regulatory reports	Regulatory financial statements are provided as well as physical submissions this is information on the physical outputs and indicators
Purpose of regulatory reports	Serves various functions including determining performance against forecast, assessments over time, and to allow for adjustments for over and under recoveries.
Requirement for reconciliation with audited financial statements	Yes
Key information sources	
- *NRA:* https://www.acm.nl/en - *Methodology:* https://www.acm.nl/nl/publicaties/publicatie/16965/Methodebesluit-GTS-2017-2021	

16.1.9 Romania

Romania

Regulatory, market and policy framework		
Regulator	Romanian Energy Regulatory Authority (ANRE)	
TSO(s)	SNTGN Transgaz SA	
Customer mix	Residential/commercial	32%
	Large industrial	41%
	Power generation	27%
Ratio of transit to national flows	145%	
Network age and length	Pipeline length	13,350 km
	Original operation	1914
Regulatory governance and process		
Entity that establishes the methodology and sets allowed/target revenues	The revenue setting methodology is set by the NRA with the TSO having a participatory role. Allowed revenues are set by the NRA	
Length of revenue setting process	NRA must approve tariffs at least one month before the annual auction for capacity yearly products. The process takes three-four months.	
Parties that can appeal NRA-determined revenues	Anyone with a legitimate interest can appeal the decision to the Courts	
Type of appeal that is allowed	Limited merits review	
Overall framework for setting allowed revenues		
Type of regulation	A revenue cap	
Approach to assembling the cost base	Building blocks approach	
Duration of regulatory period	Five years. However, the current regulatory period was extended by exception to seven years, so that it ends in 2019 and therefore coincides with the time when new tariffs complying with the Gas Tariff Network Code must apply.	
Determining and setting operating expenditures		
Cost categories partially or fully passed through	▪ Royalties ▪ Rents with government authorities ▪ Taxes and contributions stipulated by law ▪ Contributions to health funds and other special funds required by law ▪ Bad debts due to bankruptcy (as established by courts)	
Methods and approaches to assessing and setting opex allowances	Bottom-up approach Trend analysis employed for energy and water costs, advertising costs and social costs Methodology assessment for maintenance costs, third-party expenses, technical losses, and material and inventory costs	
Inclusion of efficiency or productivity improvements	Yes	

Romania

Efficiency factors used in most recent regulatory period	The factor used in the current regulatory period is 3.5%. The efficiency factor used was based on several elements including productivity levels in the broader economy and in comparator companies, and justified proposals from the TSO	
Treatment of gas shrinkage	This must ultimately be based on a methodology developed by ANRE – a proposed approach has been published for public consultation, but has not been approved yet. In the meantime, pass-through of the TSO-calculated losses is used (and these are valued using actual purchase prices)	
Determining and setting capital expenditures		
Methods and approaches to assessing and setting allowances	NRA approves the investments plan of the TSO annually. Only planned investments are recognised for revenue-setting purposes and investments are reviewed *ex post* for their efficiency	
Use of uncertainty mechanisms	None	
Inclusion of efficiency or productivity improvements	No	
Efficiency factors used in most recent regulatory period	N/A	
Use of ex post reviews before rolling capital expenditure or assets into the RAB	The expenditure has to be necessary, opportune, efficient and reflect market conditions. The TSO assesses this in the investment plans and then reassesses *ex-post*	
Use of tendering for large system expansions	Yes	
Regulatory asset base (RAB)		
Method used for setting the opening asset value (at the time of establishing the new regulatory framework)	A value that rolled forward directly from the value *implicitly* used in previous tariff or revenue decisions or approvals	
Depreciation of closing asset value as a single asset or as separate asset categories	Asset categories are depreciated individually	
Revaluation of the RAB	No, the RAB is updated for actual investment costs and depreciation	
Major assets included in the RAB	Pipelines, gas receiving stations, compressors, control stations, metering stations, buildings, vehicles, technical equipment and other equipment, land	
Inclusion and treatment of linepack	Not included	
Inclusion and treatment of working capital	Not included	
Timing of rolling investments into the RAB	When a capital project is commissioned Assets are rolled into the RAB, inclusive of interest costs and charges incurred and normally capitalised under accounting standards	
Depreciation		
Method	Straight-line depreciation	
Asset lives (for major asset groupings)	Pipelines	25-40 years (depending on pipe specification)
	Compressors	40 years

Romania

<table>
<tr><td rowspan="2"></td><td>Controllers/metering stations</td><td>10-20 years (depending on specification)</td></tr>
<tr><td>SCADA, telecoms</td><td>-</td></tr>
<tr><td colspan="3">Cost of capital and financeability</td></tr>
<tr><td>WACC method</td><td colspan="2">Post tax nominal</td></tr>
<tr><td rowspan="2">WACC value set in the two most recent regulatory periods</td><td>Previous regulatory period</td><td>Current regulatory period</td></tr>
<tr><td>10.4%</td><td>9.41%</td></tr>
<tr><td>WACC premium for specific investments or risks</td><td colspan="2">Yes, a premium may be granted for new interconnectors and capital expenditure which leads to increased operational efficiency
The investment specific premium is 1.4% in addition to rate of return</td></tr>
<tr><td>Primary (or only) methodology for setting the cost of equity</td><td colspan="2">Capital Asset Pricing Model (CAPM)</td></tr>
<tr><td>Method for setting the risk-free rate (RFR)</td><td colspan="2">10-year Romanian government bonds</td></tr>
<tr><td>Method for setting the equity or market risk premium (MRP/ERP)</td><td colspan="2">Calculated as the average between the MRP obtained with Damodaran estimates and the MRP published by BVB (Bucharest Stock Exchange) using the Bucharest Exchange Trading index. The DMS/Credit Suisse publication for the period 1900 to 2010 is seemingly used as a sense-check too.</td></tr>
<tr><td>Method for establishing the equity beta</td><td colspan="2">By calculation and reference to regulatory precedents or other analysis. The beta is calculated using Bucharest Stock Exchange data for Transgaz and Transelectrica and also by reference to betas estimated for European network operators</td></tr>
<tr><td>WACC parameters
(RP = Regulatory Period
CoE = Cost of Equity)</td><td colspan="2"><table><tr><td></td><td>RFR</td><td>MRP</td><td>Equity beta</td><td>Asset beta</td><td>CoE</td></tr><tr><td>Prev. RP</td><td>7.34%</td><td>6.1%</td><td>0.678</td><td>0.53</td><td>11.48%</td></tr><tr><td>Current RP</td><td>6.94%</td><td>6.42%</td><td>0.64</td><td>0.42</td><td>11.03%</td></tr></table></td></tr>
<tr><td>Method for setting the cost of debt</td><td colspan="2">Ex ante allowance for the cost of debt based on references to a group of European TSOs in the gas and electricity sector</td></tr>
<tr><td>Inclusion of debt issuance costs</td><td colspan="2">No</td></tr>
<tr><td>Cost of debt parameters</td><td colspan="2"><table><tr><td>Previous regulatory period</td><td>Debt premium (if relevant)</td><td>Cost of debt (net of issuance costs)</td><td>Debt issuance costs (if relevant)</td></tr><tr><td>Previous regulatory period</td><td>1.10%</td><td>8.44%</td><td>-</td></tr><tr><td>Current regulatory period</td><td>0.35%</td><td>7.29%</td><td>-</td></tr></table></td></tr>
<tr><td>Gearing approach</td><td colspan="2">Notional</td></tr>
<tr><td rowspan="2">Gearing level</td><td>Previous regulatory period</td><td>33.33%</td></tr>
<tr><td>Current regulatory period</td><td>33.33%</td></tr>
</table>

Romania	
Financeability assessment	No
Other regulatory mechanisms (revenue adjustments and incentives)	
Treatment of accumulated over or under-recoveries of revenues	Adjusted both within and between regulatory periods. If the over or under-recoveries require a significant change to allowed revenues, ANRE may decide to spread the adjustment over several years. Adjustments are carried forward using CPI
Adjustment mechanisms for differences between forecasted or allowed operating expenditures and realised spend	Adjustments are made for underspends with the TSO allowed to retain the benefits of an underspend for 5 years before the adjustments are accounted for. Adjustments are indexed for inflation (CPI)
Adjustment mechanisms for differences between forecasted or allowed capital expenditures and realised spend	No adjustments made
Treatment of capital expenditure deferrals	None
Other revenue adjustment or incentive mechanisms	No
Regulatory reporting	
Requirement for and frequency of regulatory reporting	Yes, annually
Coverage of regulatory reports	Regulatory financial statements
Purpose of regulatory reports	To allow the NRA to calculate the applicable adjustments to apply to allowed revenues in the following regulatory period because of differences between actual and forecast outcomes in the current period
Requirement for reconciliation with audited financial statements	Yes

Key information sources

- *NRA:* www.anre.ro
- *Methodology:* http://new.transgaz.ro/sites/default/files/uploads/users/admin/Ordin%20nr.%2032%20din%2021%20mai%202014-Metodologie%20E-E.pdf

16.1.10 Sweden

Sweden		
Regulatory, market and policy framework		
Regulator	Swedish Energy Markets Inspectorate	
TSO(s)	Swedegas	
Customer mix	Residential/commercial	16%
	Large industrial	52%
	Power generation	32%
Ratio of transit to national flows	No transit flows	
Network age and length	Pipeline length	601 km
	Original operation	1985
Regulatory governance and process		
Entity that establishes the methodology and sets allowed/target revenues	The NRA sets the methodology for revenue setting and is responsible for its approval. However, the government more broadly can initiate a review of the methodology.	
Length of revenue setting process	4 months	
Parties that can appeal NRA-determined revenues	The TSO can appeal to the Courts	
Type of appeal that is allowed	A full merits appeal is allowed	
Overall framework for setting allowed revenues		
Type of regulation	A revenue cap model is in place in Sweden	
Approach to assembling the cost base	A building blocks approach	
Duration of regulatory period	4 years	
Determining and setting operating expenditures		
Cost categories partially or fully passed through	Fully passed through items include network losses, government fees and taxes	
Methods and approaches to assessing and setting opex allowances	The opex allowances are calculated using top-down assessments on broad cost categories. The cost categories are also segmented into controllable and uncontrollable costs. Where costs are controllable an efficiency factor is also factored into the allowance	
Inclusion of efficiency or productivity improvements	Yes	
Efficiency factors used in most recent regulatory period	1%/year	
Treatment of gas shrinkage	Gas shrinkage is included as part of network losses and is a full pass-through cost	
Determining and setting capital expenditures		
Methods and approaches to assessing and setting allowances	Allowances are set based on proposals from the TSO. The NRA may seek to verify that the assets are actually used for the network (*ex post*)	

Sweden

Use of uncertainty mechanisms	A fixed unit cost method is applied to pipelines, meter and regulation stations and meters	
Inclusion of efficiency or productivity improvements	Yes	
Efficiency factors used in most recent regulatory period	1%	
Use of ex post reviews before rolling capital expenditure or assets into the RAB	No, although (as stated above) the NRA can examine whether assets are being utilised	
Use of tendering for large system expansions	No	
Regulatory asset base (RAB)		
Method used for setting the opening asset value (at the time of establishing the new regulatory framework)	Historical cost of assets (as depreciated based on regulatory asset lives)	
Depreciation of closing asset value as a single asset or as separate asset categories	As separate asset categories	
Revaluation of the RAB	No	
Major assets included in the RAB	Pipelines, metering stations, metering and regulation stations, support and surveillance systems	
Inclusion and treatment of linepack	Not included	
Inclusion and treatment of working capital	Not included	
Timing of rolling investments into the RAB	Investment costs are added when incurred/at time of construction	
Depreciation		
Method	Straight-line depreciation	
Asset lives (for major asset groupings)	Pipelines	90
	Compressors	-
	Controllers/metering stations	40
	SCADA, telecoms	8
Cost of capital and financeability		
WACC method	Real pre-tax	
WACC value set in the two most recent regulatory periods	***Previous regulatory period***	***Current regulatory period***
	N/A – unregulated in the previous regulatory period	6.91%
WACC premium for specific investments or risks	Yes, a premium of 1.5% is used (which appears to apply to all investments)	
Primary (or only) methodology for setting the cost of equity	Capital Asset Pricing Model (CAPM)	
Method for setting the risk-free rate (RFR)	Based on forecasts for the yield on 10-year Swedish government bonds. The forecasts are sourced from the Swedish Central bank (Riksbanken) for 2015 and 2016 and from the National Agency for Economic Research for 2017 and 2018.	

Sweden

	The average of these calculations is then used to calculate the risk-free rate
Method for setting the equity or market risk premium (MRP/ERP)	The MRP was based on the historical adjusted risk premium (1900-2001, DMS/Credit Suisse) and a consultant's report on Swedish market participants' expectations. DMS' historical data for Sweden was adjusted down by 2.1%, which is the same level of adjustment made for UK. The resulting MRP also correlates with the average outcome for the period 1998-2012 as reflected in the consultant's report.
Method for establishing the equity beta	Calculated using the stock market index (Capital IQ), stock values of comparative companies in Western Europe and North America over a four-year period

WACC parameters
(RP = Regulatory Period
CoE = Cost of Equity)

	RFR	***MRP***	***Equity beta***	***Asset beta***	***CoE***
Prev. RP	***NA***	***NA***	***NA***	***NA***	***NA***
Current RP	4.0%	5.0%	0.76	0.45	9.31%[72]

Method for setting the cost of debt	RFR plus debt premium The premium is determined as the spread between German 10-year government bonds and BBB-rated utility bonds (with a 10-year maturity) calculated over five years
Inclusion of debt issuance costs	No

Cost of debt parameters

Previous regulatory period	***Debt premium (if relevant)***	***Cost of debt (net of issuance costs)***	***Debt issuance costs (if relevant)***
Previous regulatory period	N/A	N/A	**-**
Current regulatory period	1.80%	5.80%	-

Gearing approach	Notional	
Gearing level	***Previous regulatory period***	N/A
	Current regulatory period	47%
Financeability assessment	No	
Other regulatory mechanisms (revenue adjustments and incentives)		
Treatment of accumulated over or under-recoveries of revenues	Adjusted between regulatory periods and carried forward using CPI. Under current legislation, under-recoveries can also be carried forward over a longer period	
Adjustment mechanisms for differences between forecasted or allowed operating expenditures and realised spend	No (the TSO incurs/retains the costs and benefits of the over or underspend for the regulatory period)	

[72] This includes the 'WACC premium' of 1.5%.

Sweden

Adjustment mechanisms for differences between forecasted or allowed <u>capital expenditures</u> and realised spend	No (the TSO incurs/retains the costs and benefits of the over or underspend for the regulatory period)
Treatment of capital expenditure deferrals	None
Other revenue adjustment or incentive mechanisms	A penalty fee applies if actual revenues exceed allowed revenues by more than 5% The penalty fee is calculated as follows: Reference rate according to the interest rate act + 15% points (1.5% + 15% = 16.5%) This is calculated on the entire excess amount In the next regulatory period, allowable revenue is reduced by this amount
Regulatory reporting	
Requirement for and frequency of regulatory reporting	Yes, annual reporting
Coverage of regulatory reports	Regular financial statements are required from the TSO
Purpose of regulatory reports	To identify TSO performance relative to forecast outcomes and to support the NRA with the appropriate adjustments in the next regulatory period
Requirement for reconciliation with audited financial statements	No
Key information sources	
- *NRA:* https://ei.se/ - *Market report:* https://www.ei.se/PageFiles/310277/Ei_R2017_06.pdf	

16.1.11 Slovenia

Slovenia		
Regulatory, market and policy framework		
Regulator	Agencija na slovenskem energetskem trgu (the Energy Agency)	
TSO(s)	Plinovodi d.o.o.	
Customer mix	Residential/commercial	43.8%
	Large industrial	55.9%
	Power generation	0.30%
Ratio of transit to national flows	1.49	
Network age and length	Pipeline length	1,156 km
	Original operation	1978
Regulatory governance and process		
Entity that establishes the methodology and sets allowed/target revenues	The NRA develops and approves the tariff setting methodology and sets allowed revenues	
Length of revenue setting process	Six months	
Parties that can appeal NRA-determined revenues	An appeal can be made by the TSO to the courts	
Type of appeal that is allowed	A full merits repeal and a procedural review	
Overall framework for setting allowed revenues		
Type of regulation	Revenue cap	
Approach to assembling the cost base	A building blocks approach is taken	
Duration of regulatory period	Three years (previously two years)	
Determining and setting operating expenditures		
Cost categories partially or fully passed through	Some categories like duties, mandatory membership fees and gas for own use are fully passed through whereas other costs required by law are partially passed through	
Methods and approaches to assessing and setting opex allowances	Bottom-up assessment	
Inclusion of efficiency or productivity improvements	Yes, based on the ‘Slovenian Forecasts of Economic Trends’ published by the Institute of Macroeconomic Analysis and Development	
Efficiency factors used in most recent regulatory period	1.5% for 2016 1.4%for 2017 and 2018	
Treatment of gas shrinkage	Gas shrinkage is treated as a full pass-through costs, up to a maximum of 2% of transported gas volumes	
Determining and setting capital expenditures		
Methods and approaches to assessing and setting allowances	A bottom-up assessment with business cases (CBA) for major infrastructure projects	
Use of uncertainty mechanisms	No	

Slovenia

Inclusion of efficiency or productivity improvements	No	
Efficiency factors used in most recent regulatory period	N/A	
Use of ex post reviews before rolling capital expenditure or assets into the RAB	No	
Use of tendering for large system expansions	For expansions over a certain amount the TSO must competitively tender the projects	
Regulatory asset base (RAB)		
Method used for setting the opening asset value (at the time of establishing the new regulatory framework)	The historical cost of the assets as per the TSO's statutory accounts at the time.	
Depreciation of closing asset value as a single asset or as separate asset categories	Asset categories are depreciated individually	
Revaluation of the RAB	No	
Major assets included in the RAB	Pipelines, gas receiving stations, compressors , control stations, metering stations, SCADA/telecoms, linepack, metering and regulation stations, large consumer connection assets	
Inclusion and treatment of linepack	Linepack is included in the asset and included as a depreciated asset with a finite lifetime	
Inclusion and treatment of working capital	No	
Timing of rolling investments into the RAB	When the project is commissioned but without including the financing costs	
Depreciation		
Method	Straight line depreciation	
Asset lives (for major asset groupings)	Pipelines	35 years
	Compressors	5-15 years
	Controllers/metering stations	15 years
	SCADA, telecoms	6 years
Cost of capital and financeability		
WACC method	Pre-tax nominal	
WACC value set in the two most recent regulatory periods	***Previous regulatory period***	***Current regulatory period***
	-	6.98%
WACC premium for specific investments or risks	No	
Primary (or only) methodology for setting the cost of equity	Capital Asset Pricing Model (CAPM)	
Method for setting the risk-free rate (RFR)	German 10-year government bonds Measurement period: 2003-2008	
Method for setting the equity or market risk premium (MRP/ERP)	Based on different data sources and adjusted for Slovenia. Data sources include: Duff & Phelps - 2014 Valuation handbook, Credit Suisse - Global Investment Return Yearbook 2014, and the Pablo Fernandez – Market Risk premium used in 88	

Slovenia

<table>
<tr><td></td><td>countries in 2014
A country risk premium of 1.75% is added (Aswath Damodaran)</td></tr>
<tr><td>Method for establishing the equity beta</td><td>The equity beta is established through calculation using information on 24 EU companies</td></tr>
<tr><td>WACC parameters
(RP = Regulatory Period
CoE = Cost of Equity)</td><td><table>
<tr><th></th><th>RFR</th><th>MRP</th><th>Equity beta</th><th>Asset beta</th><th>CoE</th></tr>
<tr><td>Prev. RP</td><td>-</td><td>-</td><td>-</td><td>-</td><td>-</td></tr>
<tr><td>Current RP</td><td>3.53%</td><td>6.75%</td><td>1.07</td><td>0.45</td><td>10.63%</td></tr>
</table></td></tr>
<tr><td>Method for setting the cost of debt</td><td>The cost of debt is determined ex ante, based on the RFR plus a debt premium (not clear how the latter is set)</td></tr>
<tr><td>Inclusion of debt issuance costs</td><td>No</td></tr>
<tr><td>Cost of debt parameters</td><td><table>
<tr><th>Previous regulatory period</th><th>Debt premium (if relevant)</th><th>Cost of debt (net of issuance costs)</th><th>Debt issuance costs (if relevant)</th></tr>
<tr><td>Previous regulatory period</td><td>-</td><td>-</td><td>-</td></tr>
<tr><td>Current regulatory period</td><td>0.40%</td><td>3.93%</td><td>-</td></tr>
</table></td></tr>
<tr><td>Gearing approach</td><td>Notional</td></tr>
<tr><td>Gearing level</td><td><table>
<tr><td>Previous regulatory period</td><td>-</td></tr>
<tr><td>Current regulatory period</td><td>60%</td></tr>
</table></td></tr>
<tr><td>Financeability assessment</td><td>No</td></tr>
<tr><td colspan="2">Other regulatory mechanisms (revenue adjustments and incentives)</td></tr>
<tr><td>Treatment of accumulated over or under-recoveries of revenues</td><td>Adjusted between regulatory periods, and carried forward using an interest rate of 2% (for the 2016-18 regulatory period)</td></tr>
<tr><td>Adjustment mechanisms for differences between forecasted or allowed <u>operating expenditures</u> and realised spend</td><td>None</td></tr>
<tr><td>Adjustment mechanisms for differences between forecasted or allowed <u>capital expenditures</u> and realised spend</td><td>None</td></tr>
<tr><td>Treatment of capital expenditure deferrals</td><td>None</td></tr>
<tr><td>Other revenue adjustment or incentive mechanisms</td><td>No</td></tr>
<tr><td colspan="2">Regulatory reporting</td></tr>
<tr><td>Requirement for and frequency of regulatory reporting</td><td>Yes, annual regulatory reporting is required</td></tr>
<tr><td>Coverage of regulatory reports</td><td>Regulatory financing statements are expected alongside updates on the physical state of the infrastructure against targets and outputs set by the NRA</td></tr>
<tr><td>Purpose of regulatory reports</td><td>The regulatory reports identify how the TSO is performing with</td></tr>
</table>

Slovenia

	relation to the forecasts and allow consistent assessments over time of the TSO's cost efficiency and productivity.
Requirement for reconciliation with audited financial statements	Yes
Key information sources	

- *NRA:* https://www.agen-rs.si/web/en
- *Methodology:* http://www.pisrs.si/Pis.web/pregledPredpisa?id=AKT_929

16.1.12 Great Britain

Great Britain		
Regulatory, market and policy framework		
Regulator	Office of Gas and Electricity Markets (Ofgem)	
TSO(s)	National Grid Gas Transmission Plc (NGGT)	
Customer mix	Residential/commercial	Not provided
	Large industrial	Not provided
	Power generation	Not provided
Ratio of transit to national flows		
Network age and length	Pipeline length	Not provided
	Original operation	Not provided
Regulatory governance and process		
Entity that establishes the methodology and sets allowed/target revenues	Ofgem (NRA)	
Length of revenue setting process	6-12 months (occurs once every 5 – 8 years)	
Parties that can appeal NRA-determined revenues	Appeals are to the Competition and Markets Authority by the TSO, system users, and other interested parties	
Type of appeal that is allowed	All types of appeal are allowed (limited merits, full merits, procedural review)	
Overall framework for setting allowed revenues		
Type of regulation	Revenue cap	
Approach to assembling the cost base	TOTEX approach	
Duration of regulatory period	8 years (currently, but subject to review)	
Determining and setting operating expenditures		
Cost categories partially or fully passed through	Uncontrollable expenses are fully passed through (subject to approval). Includes: ▪ Licence fees ▪ Business rates (if approved) ▪ Security costs (for 'critical' infrastructure) ▪ Quarry claims (if approved)	
Methods and approaches to assessing and setting opex allowances	Ofgem uses an overall TOTEX approach to determine allowed revenues. However, benchmarking and bottom-up assessments are also used to assess the robustness of NGGT's business plans.	
Inclusion of efficiency or productivity improvements	Yes	
Efficiency factors used in most recent regulatory period	Not specified – embedded in the cost allowances	
Treatment of gas shrinkage	Incentivised to investigate the causes of 'Unaccounted for Gas', one of the components of shrinkage	

Great Britain

Determining and setting capital expenditures		
Methods and approaches to assessing and setting allowances	A TOTEX approach is generally used. However, other analytical tools eg bottom-up assessments, detailed project reviews and business case analysis, amongst others, are also used to assess the rigour of the proposed capital expenditure	
Use of uncertainty mechanisms	Uncertainty mechanisms are used as appropriate eg fixed unit costs with a volume driver for some repex. Re-openers are also permitted on ad hoc basis. For the current price control framework there were two re-openers, one in 2015 and the other in 2018. These allowed NGGT to petition for funds in areas where capital expenditure was deemed too uncertain to be rolled into the allowed revenues at the beginning of the regulatory period.	
Inclusion of efficiency or productivity improvements	Yes	
Efficiency factors used in most recent regulatory period	Not specified – embedded in the cost allowances	
Use of ex post reviews before rolling capital expenditure or assets into the RAB	Yes	
Use of tendering for large system expansions	Has not been relevant, but such a requirement would be possible if there were to be significant system expansions	
Regulatory asset base (RAB)		
Method used for setting the opening asset value (at the time of establishing the new regulatory framework)	An independent valuation was undertaken at the time of privatising the vertically-integrated British Gas	
Depreciation of closing asset value as a single asset or as separate asset categories	Single asset depreciation (before the introduction of 'RIIO', the current UK methodology, depreciation was on an accelerated basis)	
Revaluation of the RAB	RAB is not revalued (but has inflation applied, given it is a real-price regime)	
Major assets included in the RAB	There is no differentiation by assets class given the TOTEX approach. The RAB is treated as a single asset which depreciated on a straight-line basis over 45 years	
Inclusion and treatment of linepack	N/A	
Inclusion and treatment of working capital	Working capital is included in the RAB	
Timing of rolling investments into the RAB	Expenditure enters the RAB as incurred	
Depreciation		
Method	Straight-line depreciation for new assets (and accelerated depreciation for older assets still in the RAB)	
Asset lives (for major asset groupings)	Pipelines	45 year straight line depreciation for all new assets
	Compressors	
	Controllers/metering stations	
	SCADA, telecoms	

Great Britain

<table>
<tr><th colspan="2">Cost of capital and financeability</th></tr>
<tr><td>WACC method</td><td>An allowed WACC is set on a vanilla basis in real terms</td></tr>
<tr><td>WACC value set in the two most recent regulatory periods</td><td><table><tr><th>Previous regulatory period</th><th>Current regulatory period</th></tr><tr><td>5.05%</td><td>4.38%</td></tr></table></td></tr>
<tr><td>WACC premium for specific investments or risks</td><td>No, a WACC premium is not allowed for specific investments</td></tr>
<tr><td>Primary (or only) methodology for setting the cost of equity</td><td>Capital Asset Pricing Model (CAPM)</td></tr>
<tr><td>Method for setting the risk-free rate (RFR)</td><td>Historical yields of UK government bonds and of other country government bonds</td></tr>
<tr><td>Method for setting the equity or market risk premium (MRP/ERP)</td><td>There is no defined method to set the MRP/ERP. Ofgem uses various techniques, proposes a premium, offers NGGT (and others) an opportunity to comment on the proposals before finalising.</td></tr>
<tr><td>Method for establishing the equity beta</td><td>By reference to regulatory precedent elsewhere and by calculation</td></tr>
<tr><td>WACC parameters
(RP = Regulatory Period
CoE = Cost of Equity)</td><td><table><tr><th></th><th>RFR</th><th>MRP</th><th>Equity beta</th><th>Asset beta</th><th>CoE</th></tr><tr><td>Prev. RP[73]</td><td>-</td><td>-</td><td>-</td><td>-</td><td>7.0%</td></tr><tr><td>Current RP[74]</td><td>-</td><td>-</td><td>-</td><td>-</td><td>6.8%</td></tr></table></td></tr>
<tr><td>Method for setting the cost of debt</td><td>Set on a trailing basis using an index of corporate bonds. Ofgem uses the ‘iBoxx non-financials index’ for A and BBB credit ratings</td></tr>
<tr><td>Inclusion of debt issuance costs</td><td>No</td></tr>
<tr><td>Cost of debt parameters</td><td><table><tr><th></th><th>Debt premium (if relevant)</th><th>Cost of debt (net of issuance costs)</th><th>Debt issuance costs (if relevant)</th></tr><tr><td>Previous regulatory period</td><td>-</td><td>3.75%</td><td>-</td></tr><tr><td>Current regulatory period</td><td>-</td><td>2.92%</td><td>-</td></tr></table></td></tr>
<tr><td>Gearing approach</td><td>Notional</td></tr>
<tr><td>Gearing level</td><td><table><tr><td>Previous regulatory period</td><td>60%</td></tr><tr><td>Current regulatory period</td><td>62.5%</td></tr></table></td></tr>
<tr><td>Financeability assessment</td><td>Yes, and if the TSO was seen to be not financeable future revenues would be brought forward in a neutral way
All metrics listed in the questionnaire are used</td></tr>
</table>

[73] Ofgem no longer reports on the individual WACC parameters.
[74] As above.

Great Britain

Other regulatory mechanisms (revenue adjustments and incentives)	
Treatment of accumulated over or under-recoveries of revenues	Over or under recoveries are adjusted within the regulatory period, annually with a two-year lag. The adjustments are carried forward using the WACC, unless they are material in which case a 'penalty' rate applies (broadly, WACC *minus* 1 percentage point)
Adjustment mechanisms for differences between forecasted or allowed <u>operating expenditures</u> and realised spend	No differentiation is made between the operating expenditure and capital expenditure under the TOTEX approach. The adjustments are made symmetrically and apply to over and underperformance symmetrically. The sharing rate of over and underspends is 44.36% ie the share that NGGT bares. Adjustments are made using the allowed WACC
Adjustment mechanisms for differences between forecasted or allowed <u>capital expenditures</u> and realised spend	
Treatment of capital expenditure deferrals	Various mechanisms are used to ensure deferrals are efficient eg use of volume or output drivers (if these are not met, then revenue from deferrals is clawed back), no allowances are given again for the same expenditure in future, re-openers are possible if underspend is material, etc.
Other revenue adjustment or incentive mechanisms	Yes (various, including financial, statutory and reputational incentives)
Regulatory reporting	
Requirement for and frequency of regulatory reporting	Yes, annually
Coverage of regulatory reports	Regulatory financial statements and financial submissions
Purpose of regulatory reports	To identify how the TSO is performing relative to forecast outcomes and the reasons for differences To allow consistent assessments over time of the TSO's cost efficiency and productivity, so informing future regulatory decisions
Requirement for reconciliation with audited financial statements	Yes
Key information sources	

- *NRA:* https://www.ofgem.gov.uk/
- *Methodology:* https://www.ofgem.gov.uk/network-regulation-riio-model

16.1.13 Northern Ireland

Northern Ireland

Regulatory, market and policy framework	
Regulator	Northern Ireland Authority for Utility Regulation
TSO(s)	Premier Transmission Belfast Gas Transmission GNI (UK) *GNI is the most significant TSO in Northern Ireland and the remainder of the form focuses on them*
Customer mix	Residential/commercial 37% Large industrial Power generation 63%
Ratio of transit to national flows	
Network age and length	Pipeline length 543 km Original operation 1996
Regulatory governance and process	
Entity that establishes the methodology and sets allowed/target revenues	Northern Ireland Authority for Utility Regulation
Length of revenue setting process	10 months
Parties that can appeal NRA-determined revenues	TSO and system users
Type of appeal that is allowed	Full merits review
Overall framework for setting allowed revenues	
Type of regulation	Revenue cap
Approach to assembling the cost base	Building block approach is used but other techniques may be used to check, or confirm the approach used
Duration of regulatory period	5 years
Determining and setting operating expenditures	
Cost categories partially or fully passed through	Full pass-through costs include: Licence fees, Business Rates, Compressor fuel, infrastructure sharing costs in Scotland
Methods and approaches to assessing and setting opex allowances	Bottom-up assessments, trend analysis, technical or engineering reviews
Inclusion of efficiency or productivity improvements	Yes
Efficiency factors used in most recent regulatory period	1%/year
Treatment of gas shrinkage	Gas shrinkage is mainly dealt as gas lost in exporting compressors from UK-GB. Therefore, there is assumed to be no gas shrinkage for revenue allowance purposes

Northern Ireland

Determining and setting capital expenditures		
Methods and approaches to assessing and setting allowances	Ex-ante allowances are set using a bottom-up approach which includes detailed programme reviews, and business case analysis	
Use of uncertainty mechanisms	A budget ceiling approach is used with requests for reassessments contingent on the case presented to the Regulator	
Inclusion of efficiency or productivity improvements	No	
Efficiency factors used in most recent regulatory period	N/A	
Use of ex post reviews before rolling capital expenditure or assets into the RAB	May be used for assessing future allowed revenues	
Use of tendering for large system expansions	Northern Ireland has multiple TSOs, the main one (GNI) is described in this form. Some projects may be given to a different TSO depending on their nature Each TSO is expected to run a competitive tendering process to deliver the best value for consumers.	
Regulatory asset base (RAB)		
Method used for setting the opening asset value (at the time of establishing the new regulatory framework)	A value that rolled forward directly from the value explicitly used in previous tariff or revenue decisions or approvals	
Depreciation of closing asset value as a single asset or as separate asset categories	The RAB is depreciated as a single asset (with a weighted average asset life)	
Revaluation of the RAB	No	
Major assets included in the RAB	Major assets include pipelines, control stations, metering stations, metering and regulation stations and large consumer connection assets	
Inclusion and treatment of linepack	Not a material inclusion in the RAB	
Inclusion and treatment of working capital	Working capital is not included in the RAB	
Timing of rolling investments into the RAB	Assets are included in the RAB when they are commissioned	
Depreciation		
Method	Straight-line depreciation	
Asset lives (for major asset groupings)	Pipelines	43 years
	Compressors	N/A
	Controllers/metering stations	20 years
	SCADA, telecoms	-
Cost of capital and financeability		
WACC method	Vanilla WACC is set in real terms	

Northern Ireland

<table>
<tr><td rowspan="2">WACC value set in the two most recent regulatory periods</td><td colspan="3">Previous regulatory period</td><td colspan="3">Current regulatory period</td></tr>
<tr><td colspan="3">1.98%</td><td colspan="3">2.11%</td></tr>
<tr><td>WACC premium for specific investments or risks</td><td colspan="6">No</td></tr>
<tr><td>Primary (or only) methodology for setting the cost of equity</td><td colspan="6">Capital Asset Pricing Model (CAPM)</td></tr>
<tr><td>Method for setting the risk-free rate (RFR)</td><td colspan="6">At the most recent price control, the most material consideration was the historical yield of UK government bonds</td></tr>
<tr><td>Method for setting the equity or market risk premium (MRP/ERP)</td><td colspan="6">Primarily based on regulatory precedent eg by analysing the precedents that UK regulators such as Ofgem, Ofwat and the CMA have made in price control determinations over the recent past (5 to 10 years)</td></tr>
<tr><td>Method for establishing the equity beta</td><td colspan="6">As above by reference to regulatory precedent elsewhere</td></tr>
<tr><td rowspan="3">WACC parameters
(RP = Regulatory Period
CoE = Cost of Equity)</td><td></td><td>RFR</td><td>MRP</td><td>Equity beta</td><td>Asset beta</td><td>CoE</td></tr>
<tr><td>Prev RP</td><td>-</td><td>-</td><td>-</td><td>-</td><td>12.75%</td></tr>
<tr><td>Current RP</td><td>1.25%</td><td>6.5%</td><td>0.79</td><td>0.34</td><td>6.38%[75]</td></tr>
<tr><td>Method for setting the cost of debt</td><td colspan="6">Allowances for debt are set ex- ante based on current/spot estimates of recent bond issuances or by reference to s a specific comparator company</td></tr>
<tr><td>Inclusion of debt issuance costs</td><td colspan="6">No</td></tr>
<tr><td rowspan="3">Cost of debt parameters</td><td colspan="3"></td><td>Debt premium (if relevant)</td><td>Cost of debt (net of issuance costs)</td><td>Debt issuance costs (if relevant)</td></tr>
<tr><td colspan="3">Previous RP</td><td>-</td><td>3.2%</td><td>-</td></tr>
<tr><td colspan="3">Current RP</td><td>-</td><td>0.2%</td><td>-</td></tr>
<tr><td>Gearing approach</td><td colspan="6">Notional</td></tr>
<tr><td rowspan="2">Gearing level</td><td colspan="3">Previous regulatory period</td><td colspan="3">72.5%</td></tr>
<tr><td colspan="3">Current regulatory period</td><td colspan="3">65%</td></tr>
<tr><td>Financeability assessment</td><td colspan="6">Yes, these may be conducted as part of the price control</td></tr>
<tr><td colspan="7">Other regulatory mechanisms (revenue adjustments and incentives)</td></tr>
<tr><td>Treatment of accumulated over or under-recoveries of revenues</td><td colspan="6">Adjusted within the regulatory period</td></tr>
<tr><td>Adjustment mechanisms for differences between forecasted or allowed <u>operating expenditures</u> and realised spend</td><td colspan="6">Yes, but mechanisms not specified</td></tr>
</table>

[75] This was stated as 5.38%, but we have assumed it an error.

Northern Ireland

Adjustment mechanisms for differences between forecasted or allowed capital expenditures and realised spend	Yes, but mechanisms not specified
Treatment of capital expenditure deferrals	Not treated differently to other capital expenditure
Other revenue adjustment or incentive mechanisms	No
Regulatory reporting	
Requirement for and frequency of regulatory reporting	Yes, annual reporting is required
Coverage of regulatory reports	Regulatory and financial statements need to be produced
Purpose of regulatory reports	Serves various functions: 1) to identify how the TSO is performing relative to forecast outcomes; 2) to allow consistent assessments of TSOs cost efficiency and productivity; and, 3) allow information to be gathered for the next price control.
Requirement for reconciliation with audited financial statements	No
Key information sources	

- *NRA:* https://www.uregni.gov.uk
- *Methodology:* http://gmo-ni.com/assets/documents/2017-08-01-GT17-final-determination-redacted-final_0.pdf

16.2 Price cap regimes

16.2.1 Estonia

Estonia		
Regulatory, market and policy framework		
Regulator	Estonian Competition Authority	
TSO(s)	Elering AS	
Customer mix	Residential/commercial	35%
	Large industrial	63%
	Power generation	2%
Ratio of transit to national flows	No transit	
Network age and length	Pipeline length	885 km
	Original operation	1951
Regulatory governance and process		
Entity that establishes the methodology and sets allowed/target revenues	Estonian Competition Authority (NRA)	
Length of revenue setting process	1 month (up to 2 months if there is a ‘substantial’ reason)	
Parties that can appeal NRA-determined revenues	TSO	
Type of appeal that is allowed	Full merits review	
Overall framework for setting allowed revenues		
Type of regulation	(Average) Price cap	
Approach to assembling the cost base	Building block	
Duration of regulatory period	No regulatory period Cap applies until such time as the TSO submits a new tariff application (or NRA instigates review on its own accord)	
Determining and setting operating expenditures		
Cost categories partially or fully passed through	Security of Supply reserve costs are fully passed through	
Methods and approaches to assessing and setting opex allowances	Bottom-up assessment, top-down assessment, benchmarking (not regularly used due to lack of comparators), trend analysis, technical or engineering analysis Opex is generally set based on ‘efficient’ costs set in previous regulatory decision indexed for inflation and subject to ensuring costs are still reasonable and ‘needed’ using the above analytical tools	
Inclusion of efficiency or productivity improvements	No	
Efficiency factors used in most recent regulatory period	N/A	
Treatment of gas shrinkage	The average of the last three years is used for setting the	

Estonia

	allowed volume. Own gas consumption is metered and gas losses are calculated	
Determining and setting capital expenditures		
Methods and approaches to assessing and setting allowances	Reasonableness of capital expenditure is assessed when approving the 10-year network development plan. No pre-financing is provided (investments earn return and depreciation when assets enter the RAB upon commissioning)	
Use of uncertainty mechanisms	No	
Inclusion of efficiency or productivity improvements	No	
Efficiency factors used in most recent regulatory period	N/A	
Use of ex post reviews before rolling capital expenditure or assets into the RAB	No	
Use of tendering for large system expansions	Yes, required for all expansions	
Regulatory asset base (RAB)		
Method used for setting the opening asset value (at the time of establishing the new regulatory framework)	The historical cost of the assets as per the TSO's statutory accounts at the time	
Depreciation of closing asset value as a single asset or as separate asset categories	Assets are depreciated individually	
Revaluation of the RAB	No	
Major assets included in the RAB	Pipelines, gas receiving stations, metering stations, metering and regulation stations at the interface with the distribution network, large consumer connection assets	
Inclusion and treatment of linepack	Not included	
Inclusion and treatment of working capital	Yes, calculated as 5% of the last three years' turnover	
Timing of rolling investments into the RAB	When the capital project/programme is commissioned. The value is not grossed up to account for financing costs.	
Depreciation		
Method	Straight-line	
Asset lives (for major asset groupings)	Pipelines	50 years
	Compressors	N/A
	Controllers/metering stations	30 years
	SCADA, telecoms	10 years
Cost of capital and financeability		
WACC method	Vanilla, nominal	
WACC value set in the two most recent regulatory periods	***Previous regulatory period***	***Current regulatory period***
	5.63%[76]	4.51%[77]

[76] We note that this appears to be the CoE rather than the WACC.

<table>
<tr><td colspan="2">
Estonia</td></tr>
<tr><td>WACC premium for specific investments or risks</td><td>No</td></tr>
<tr><td>Primary (or only) methodology for setting the cost of equity</td><td>Capital Asset Pricing Model (CAPM)</td></tr>
<tr><td>Method for setting the risk-free rate (RFR)</td><td>5-year average of 10-year German bonds</td></tr>
<tr><td>Method for setting the equity or market risk premium (MRP/ERP)</td><td>Take arithmetic average of Belgian and Slovakian investment returns
Add estimated MRP to the RFR to estimate total market returns</td></tr>
<tr><td>Method for establishing the equity beta</td><td>By reference to regulatory precedents elsewhere</td></tr>
<tr><td>WACC parameters
(RP = Regulatory Period
CoE = Cost of Equity)</td><td>
<table>
<tr><th></th><th>RFR</th><th>MRP</th><th>Equity beta</th><th>Asset beta</th><th>CoE</th></tr>
<tr><td>Prev. RP</td><td>2.33%</td><td>4.58%</td><td>0.72</td><td>-</td><td>5.63%</td></tr>
<tr><td>Current RP</td><td>1.47%</td><td>4.55%</td><td>0.668</td><td>-</td><td>4.51%</td></tr>
</table>
</td></tr>
<tr><td>Method for setting the cost of debt</td><td>The cost of debt is calculated as the sum of:

the nominal risk-free rate. This is the 5-year (2011-2015) average interest rate of the German government 10-year bonds.
the Estonian country risk premium. According to an evaluation by the Bank of Estonia, the country risk is determined by the amount of interest that the Estonian state must pay above that of higher credit rating countries (eg Germany) when borrowing from international markets. By the end 2015, Estonia had a credit rating of A1. In accordance with A. Damodaran's database, A1 rating means a risk premium of 0.78%.
the debt risk premium. The debt risk premium is determined by the average level applied by the regulatory authorities of other countries. Utilised the CEER countries' database for electricity and gas networks. Used the CEER countries arithmetic mean indicators (CEER. Report on Investment Conditions in European Countries (confidential): March 14, 2016)
</td></tr>
<tr><td>Inclusion of debt issuance costs</td><td>No</td></tr>
<tr><td>Cost of debt parameters</td><td>
<table>
<tr><th></th><th>Debt premium (if relevant)</th><th>Cost of debt (net of issuance costs)</th><th>Debt issuance costs (if relevant)</th></tr>
<tr><td>Previous regulatory period</td><td>-</td><td>3.30%</td><td>N/A</td></tr>
<tr><td>Current regulatory period</td><td>-</td><td>3.04%</td><td>N/A</td></tr>
</table>
</td></tr>
<tr><td>Gearing approach</td><td>Notional</td></tr>
<tr><td>Gearing level</td><td>
<table>
<tr><td>Previous regulatory period</td><td>50</td></tr>
<tr><td>Current regulatory period</td><td>50</td></tr>
</table>
</td></tr>
</table>

[77] As above.

Estonia	
Financeability assessment	No
Other regulatory mechanisms (revenue adjustments and incentives)	
Treatment of accumulated over or under-recoveries of revenues	N/A (given the price cap regime)
Adjustment mechanisms for differences between forecasted or allowed operating expenditures and realised spend	N/A
Adjustment mechanisms for differences between forecasted or allowed capital expenditures and realised spend	N/A
Treatment of capital expenditure deferrals	N/A
Other revenue adjustment or incentive mechanisms	No
Regulatory reporting	
Requirement for and frequency of regulatory reporting	No reporting requirement
Coverage of regulatory reports	N/A
Purpose of regulatory reports	N/A
Requirement for reconciliation with audited financial statements	N/A
Key information sources	
- *NRA site*: http://www.konkurentsiamet.ee/?lang=en - *Natural Gas Law:* https://www.riigiteataja.ee/en/eli/524072017015/consolide - *Methodology:* http://www.konkurentsiamet.ee/index.php?id=18315	

16.2.2 Poland

Poland

Regulatory, market and policy framework		
Regulator	President of Urząd Regulacji Energetyki (URE) (Energy Regulatory Office)	
TSO(s)	Operator Gazociągów Przesyłowych GAZ-SYSTEM S.A.	
Customer mix (ITO only)	Residential/commercial	38.0%
	Large industrial	53.8%
	Power generation	8.2%
Ratio of transit to national flows	Unavailable	
Network age and length	Pipeline length	11,673 km
	Original operation	N/A
Regulatory governance and process		
Entity that establishes the methodology and sets allowed/target revenues	Calculated and submitted by the TSO Approved by the President of the URE (Although this apparently applies to the tariff methodology and not allowed revenues per se)	
Length of revenue setting process	1 month (up to 2 months for more complex cases)	
Parties that can appeal NRA-determined revenues	TSO (but can appeal tariffs not revenues per se)	
Type of appeal that is allowed	Full merits review	
Overall framework for setting allowed revenues		
Type of regulation	Price cap[78]	
Approach to assembling the cost base	Building block	
Duration of regulatory period	1 year	
Determining and setting operating expenditures		
Cost categories partially or fully passed through	Local taxes and other fees	
Methods and approaches to assessing and setting opex allowances	Bottom-up assessment, trend analysis	
Inclusion of efficiency or productivity improvements	No	
Efficiency factors used in most recent regulatory period	N/A	
Treatment of gas shrinkage	Cost of gas losses and own use is included in regulated revenue	
Determining and setting capital expenditures		
Methods and approaches to assessing and setting allowances	Bottom-up assessment	

[78] Our understanding of the Polish regulatory system would define it as price cap regulation due to the lack of revenue reconciliation. However, URE defines it as a revenue cap.

Poland

Use of uncertainty mechanisms	No	
Inclusion of efficiency or productivity improvements	No	
Efficiency factors used in most recent regulatory period	N/A	
Use of ex post reviews before rolling capital expenditure or assets into the RAB	N/A	
Use of tendering for large system expansions	Yes	
Regulatory asset base (RAB)		
Method used for setting the opening asset value (at the time of establishing the new regulatory framework)	Historical book values	
Depreciation of closing asset value as a single asset or as separate asset categories	Asset categories are depreciated individually	
Revaluation of the RAB	No, but RAB is rolled forward using planned investments subject to a correction factor if there is significant underspending	
Major assets included in the RAB	Pipelines, gas receiving stations, compressor stations, control stations, metering stations, SCADA stations and systems, metering and regulation stations at the interface with the distribution network, large consumer connection assets	
Inclusion and treatment of linepack	Not included	
Inclusion and treatment of working capital	No	
Timing of rolling investments into the RAB	When a capital project/programme is commissioned. The value is not grossed up to account for financing costs.	
Depreciation		
Method	Straight-line	
Asset lives (for major asset groupings)[79]	Pipelines	40 years
	Compressors	25 years
	Controllers/metering stations	25 years
	SCADA, telecoms	5 years
Cost of capital and financeability		
WACC method	Pre-tax, nominal	
WACC value set in the two most recent regulatory periods	***Previous regulatory period***	***Current regulatory period***
	5.64%	6.19%
WACC premium for specific investments or risks	No	

[79] URE stated it does not keep records on assets with this specific breakdown, and provided us with a chart of very broad depreciation schedules instead. We have used these to infer asset lives for the given asset categories, but these should only be treated as indicative.

Poland

Primary (or only) methodology for setting the cost of equity	Capital Asset Pricing Model (CAPM)
Method for setting the risk-free rate (RFR)	Average 18-months ratings of Polish 10-year fixed rate treasury bonds, with the longest term to maturity
Method for setting the equity or market risk premium (MRP/ERP)	Precedent set by other regulatory authorities (CEER Internal Report on Investment Conditions in European Countries, March 2014)
Method for establishing the equity beta	By reference to regulatory precedents elsewhere

WACC parameters

(RP = Regulatory Period

CoE = Cost of Equity)

	RFR	***MRP***	***Equity beta***	***Asset beta***	***CoE***
Prev. RP	2.910%	4.5%	0.4719	0.4	5.034%
Current RP	3.256%	4.5%	0.5389	0.4	5.681%

Method for setting the cost of debt	Set *ex ante* as the RFR plus a debt premium
Inclusion of debt issuance costs	No

Cost of debt parameters

	Debt premium (if relevant)	***Cost of debt (net of issuance costs)***	***Debt issuance costs (if relevant)***
Previous regulatory period	1.0%	3.910%	-
Current RP	1.0%	4.256%	-

Gearing approach	Notional	
Gearing level	***Previous regulatory period***	25
	Current regulatory period	30
Financeability assessment	No	

Other regulatory mechanisms (revenue adjustments and incentives)	
Treatment of accumulated over or under-recoveries of revenues	No mechanism for adjusting for over- or under-recoveries of revenue
Adjustment mechanisms for differences between forecasted or allowed operating expenditures and realised spend	None (although a significant underspend of a specific opex component may affect the next tariff cost forecast)
Adjustment mechanisms for differences between forecasted or allowed capital expenditures and realised spend	A 'WSK' correction factor can be applied to significant underspends (there is no pre-specified correction or sharing factor)
Treatment of capital expenditure deferrals	None, but note that actual expenditure is rolled into the RAB where there is an underspend
Other revenue adjustment or incentive mechanisms	No
Regulatory reporting	
Requirement for and frequency of regulatory reporting	Quarterly
Coverage of regulatory reports	Information on booked capacity, volume of transported gas,

Poland

	revenues, and costs
Purpose of regulatory reports	To allow consistent assessments over time of the TSO's cost efficiency and productivity, so informing future regulatory decisions
Requirement for reconciliation with audited financial statements	No
Key information sources	

- *NRA site: https://www.ure.gov.pl/en/*
  http://www.ure.gov.pl/pl/prawo/rozporzadzenia/rozporzadzenia-w-spraw
  http://bip.ure.gov.pl/bip/taryfy-i-inne-decyzje/zalozenia-dla-kalkulacj/2189,Pismo-Prezesa-Urzedu-Regulacji-Energetyki-do-przedsiebiorstw-energetycznych.html
- *Current TSO tariff: http://en.gaz-system.pl/strefa-klienta/taryfa/taryfa-i-stawki-oplat/*

16.3 Cost-plus / rate of return regimes

16.3.1 Greece

Greece		
Regulatory, market and policy framework		
Regulator	Regulatory Authority for Energy (RAE)	
TSO(s)	National Natural Gas System Operator (DESFA) S.A.	
Customer mix	Residential/commercial	21.4%
	Large industrial	10.1%
	Power generation	68.5%
Ratio of transit to national flows	n/a	
Network age and length	Pipeline length	1,464 km
	Original operation	2007 (LNG terminal started operating in 2000)
Regulatory governance and process		
Entity that establishes the methodology and sets allowed/target revenues	DESFA (TSO) develops the methodology but this and the allowed revenues are approved and set by RAE (NRA)	
Length of revenue setting process	4 months	
Parties that can appeal NRA-determined revenues	TSO, transmission system users	
Type of appeal that is allowed	Full merits review	
Overall framework for setting allowed revenues		
Type of regulation	Cost-plus	
Approach to assembling the cost base	Building block approach	
Duration of regulatory period	4 years	
Determining and setting operating expenditures		
Cost categories partially or fully passed through	All regulated OPEX	
Methods and approaches to assessing and setting opex allowances	Bottom-up assessment, trend analysis	
Inclusion of efficiency or productivity improvements	No	
Efficiency factors used in most recent regulatory period	N/A	
Treatment of gas shrinkage	Gas shrinkage (covering both self-consumption and losses) is excluded from allowed revenues. The TSO prepares a separate study which is submitted to the regulator regarding shrinkage, which in turn is recovered through a discrete tariff.	
Determining and setting capital expenditures		
Methods and approaches to assessing and setting allowances	Bottom-up assessment, detailed project/programme reviews. All investments must be approved in the National Natural Gas	

 **Greece**		
	System (NNG) Development Plan or must be included in the “Small Project’s List”, in order to be included	
Use of uncertainty mechanisms	N/A	
Inclusion of efficiency or productivity improvements	No	
Efficiency factors used in most recent regulatory period	N/A	
Use of ex post reviews before rolling capital expenditure or assets into the RAB	Capital expenditure is included in the RAB *ex ante* but at the time of the ‘Recoverable Difference’ calculation, the RAB is recalculated including the *ex post* realised expenditure	
Use of tendering for large system expansions	Yes	
Regulatory asset base (RAB)		
Method used for setting the opening asset value (at the time of establishing the new regulatory framework)	The historical cost of the assets as per the TSO’s statutory accounts at the time	
Depreciation of closing asset value as a single asset or as separate asset categories	Asset categories are depreciated individually	
Revaluation of the RAB	No	
Major assets included in the RAB	Pipelines, gas receiving stations, compressor stations, control stations, metering stations, metering and regulation stations at the interface with the distribution network	
Inclusion and treatment of linepack	No	
Inclusion and treatment of working capital	Yes - apply balance sheet method	
Timing of rolling investments into the RAB	When incurred/at time of construction	
Depreciation		
Method	Straight-line	
Asset lives (for major asset groupings)	Pipelines	40 years
	Compressors	40 years
	Controllers/metering stations	40 years
	SCADA, telecoms	5 years
Cost of capital and financeability		
WACC method	Pre-tax, nominal	
WACC value set in the two most recent regulatory periods	***Previous regulatory period***	***Current regulatory period***
	10.99%	9.22%
WACC premium for specific investments or risks	The possibility of applying a WACC premium is envisaged by the tariff regulation, but none has been applied in practice	
Primary (or only) methodology for setting the cost of equity	Capital Asset Pricing Model (CAPM)	
Method for setting the risk-free rate (RFR)	10-year German bonds	
Method for setting the equity or market risk premium (MRP/ERP)	According to Tariff Regulation: “The market risk premium, which is defined based on historical data and estimates on the	

<table>
<tr><td colspan="2">
Greece</td></tr>
<tr><td></td><td>evolution of returns of stock versus government bonds, in the largest possible sample of developed countries. To determine this parameter, information may be obtained from relevant reports of accredited financial institutions, universities, and from relevant international literature.
Add estimated MRP to RFR to estimate total market returns.</td></tr>
<tr><td>***Method for establishing the equity beta***</td><td>The tariff regulation requires that the beta be established by calculation using the data of listed gas transmission and distribution monopolies in the EU. In practice, the TSO submits its proposal and RAE assesses based on regulatory decisions elsewhere (where calculations have been made broadly in accordance with the tariff regulation).</td></tr>
<tr><td>***WACC parameters***
(RP = Regulatory Period
CoE = Cost of Equity)</td><td><table>
<tr><td></td><td>***RFR***</td><td>***MRP***</td><td>***Equity beta***</td><td>***Asset beta***</td><td>***CoE***</td></tr>
<tr><td>***Prev. RP***</td><td>0.63%</td><td>5.90%</td><td>0.5</td><td>-</td><td>10.33%</td></tr>
<tr><td>***Current RP***</td><td>0.36%</td><td>5.23%</td><td>0.6</td><td>-</td><td>10.56%</td></tr>
</table></td></tr>
<tr><td>***Method for setting the cost of debt***</td><td>*Ex ante* setting of cost of debt. Take an average of the annual cost of debt for the four-year regulatory period</td></tr>
<tr><td>***Inclusion of debt issuance costs***</td><td>No</td></tr>
<tr><td>***Cost of debt parameters***</td><td><table>
<tr><td></td><td>***Debt premium (if relevant)***</td><td>***Cost of debt (net of issuance costs)***</td><td>***Debt issuance costs (if relevant)***</td></tr>
<tr><td>***Previous regulatory period***</td><td></td><td>5.95%</td><td></td></tr>
<tr><td>***Current regulatory period***</td><td></td><td>4.46%</td><td></td></tr>
</table></td></tr>
<tr><td>***Gearing approach***</td><td>Actual</td></tr>
<tr><td>***Gearing level***</td><td><table>
<tr><td>***Previous regulatory period***</td><td>28%</td></tr>
<tr><td>***Current regulatory period***</td><td>22%</td></tr>
</table></td></tr>
<tr><td>***Financeability assessment***</td><td>No</td></tr>
<tr><td colspan="2">**Other regulatory mechanisms (revenue adjustments and incentives)**</td></tr>
<tr><td>***Treatment of accumulated over or under-recoveries of revenues***</td><td>There is an accumulated under-recovery in the period 2006-2016 amounting to €325 m and it has been decided that this be recovered over the period 2017-2032</td></tr>
<tr><td>***Adjustment mechanisms for differences between forecasted or allowed <u>operating expenditures</u> and realised spend***</td><td>There are no rolling mechanisms or revenue adjustments for incentive purposes. Opex is currently cost-plus. Any difference is taken into account in the calculation of under/over recovery.</td></tr>
<tr><td>***Adjustment mechanisms for differences between forecasted or allowed <u>capital expenditures</u> and realised spend***</td><td>There are no rolling mechanisms or revenue adjustments for incentive purposes. Capital expenditure is currently cost-plus</td></tr>
<tr><td>***Treatment of capital expenditure deferrals***</td><td>N/A</td></tr>
<tr><td>***Other revenue adjustment or incentive mechanisms***</td><td>No</td></tr>
</table>

Greece	
Regulatory reporting	
Requirement for and frequency of regulatory reporting	Annually
Coverage of regulatory reports	Regulatory financial statements
Purpose of regulatory reports	To identify how the TSO is performing relative to forecast outcomes and the reasons for differences. To allow the NRA to calculate the applicable adjustments to apply to allowed revenues in the following regulatory period because of differences between actual and forecast outcomes in the current period.
Requirement for reconciliation with audited financial statements	Yes
Key information sources	
- *NRA site:* http://www.rae.gr/old/en/ - *TSO (NRA decisions):* http://www.desfa.gr/en/regulatory-framework/greek-regulatory-framework/decisions-of-rae	

16.4 Hybrid regimes

16.4.1 Austria

Austria

Regulatory, market and policy framework		
Regulator	Energie Control Austria	
TSO(s)	Gas Connect Austria GmbH Trans Austria Gasleitung GmbH	
Customer mix	Residential/commercial	29%
	Large industrial	43%
	Power generation	28%
Ratio of transit to national flows	4.75	
Network age and length	Pipeline length	2,000 km
	Original operation	1974
Regulatory governance and process		
Entity that establishes the methodology and sets allowed/target revenues	Revenue methodology developed by the TSOs Energie Control Austria (NRA) approves the methodology Both the NRA and the TSOs can initiate changes to the methodology	
Length of revenue setting process	36 months	
Parties that can appeal NRA-determined revenues	TSO Several parties defined by law	
Type of appeal that is allowed	Limited merits, full merits, and procedural review	
Overall framework for setting allowed revenues		
Type of regulation	Hybrid - revenue cap for opex / cost-plus for capital expenditure and ‘risk volume’ (see WACC premium below)	
Approach to assembling the cost base	Building block	
Duration of regulatory period	4 years	
Determining and setting operating expenditures		
Cost categories partially or fully passed through	Energy costs Regulatory costs	
Methods and approaches to assessing and setting opex allowances	Bottom-up assessment Trend analysis	
Inclusion of efficiency or productivity improvements	Yes	
Efficiency factors used in most recent regulatory period	2.45% per year	
Treatment of gas shrinkage	Full cost pass-through	

Austria

Determining and setting capital expenditures		
Methods and approaches to assessing and setting allowances	Bottom-up assessment, detailed project/programme reviews, business case analysis	
Use of uncertainty mechanisms	No	
Inclusion of efficiency or productivity improvements	No	
Efficiency factors used in most recent regulatory period	N/A	
Use of ex post reviews before rolling capital expenditure or assets into the RAB	No	
Use of tendering for large system expansions	No	
Regulatory asset base (RAB)		
Method used for setting the opening asset value (at the time of establishing the new regulatory framework)	Debt-financed: calculated on book values Equity-financed: calculated on replacement values	
Depreciation of closing asset value as a single asset or as separate asset categories	Assets up to and including 2011: RAB depreciated as a single asset Assets after 2011: assets are depreciated individually	
Revaluation of the RAB	Equity-financed part is indexed for inflation	
Major assets included in the RAB	Pipelines, gas receiving stations, compressor stations, control stations, metering stations, SCADA stations and systems, metering and regulation stations at the interface with the distribution network	
Inclusion and treatment of linepack	Not included in the RAB	
Inclusion and treatment of working capital	Not included in the RAB	
Timing of rolling investments into the RAB	Upon commissioning. Value is not grossed up to account for financing costs.	
Depreciation		
Method	Straight-line	
Asset lives (for major asset groupings)	Pipelines	30
	Compressors	12
	Controllers/metering stations	12
	SCADA, telecoms	12
Cost of capital and financeability		
WACC method	Pre-tax real for equity, pre-tax nominal for debt	
WACC value set in the two most recent regulatory periods	***Previous regulatory period***	***Current regulatory period***
	N/A	N/A

Austria

<table>
<tr><td>WACC premium for specific investments or risks</td><td>3.5% was applied to the 'volume risk' of equity-financed assets (volume risk was incorporated with the introduction of entry/exit tariffs). Tariffs were set based on an assumed level of contracted capacity and there is then an asymmetric adjustment for realised volumes. Specifically, if volumes exceed the assumed capacity level, tariffs are adjusted (decreased) for actual volumes (so the regime operates as if it is a revenue cap), but if realised volumes are below the initially fixed capacity level, there is no corresponding adjustment (which would entail unit tariffs increasing) and therefore the TSO bears the volume risk (the regime operates like a price cap). This volume risk is calculated and the premium intends to compensate the TSO for the risk.</td></tr>
<tr><td>Primary (or only) methodology for setting the cost of equity</td><td>Capital Asset Pricing Model (CAPM)</td></tr>
<tr><td>Method for setting the risk-free rate (RFR)</td><td>5-year average of AAA-rated yields of government bonds from the EURO-area with 10 years maturity</td></tr>
<tr><td>Method for setting the equity or market risk premium (MRP/ERP)</td><td>Market Risk Premium was fixed at 5% in the 2013 regulatory period and kept constant for the 2017 regulatory period. The MRP is estimated and then the RFR is added to estimate the total market return.</td></tr>
<tr><td>Method for establishing the equity beta</td><td>Stock market index used: Country-specific index from the FTSE All-World Index series
Regulated company stocks used: ELIA, TERNA, SNAM, Redes Energgeticas, Red Electrica, Enagas, National Grid, Vector, Spark Infrastructure Group, Duet Group, Ausnet Services, Boardwalk pipeline partners, ITC Holding, TC pipelines
Estimation time period used: 3 years
Frequency of observations: daily</td></tr>
<tr><td>WACC parameters
(RP = Regulatory Period
CoE = Cost of Equity)</td><td>
<table>
<tr><th></th><th>RFR</th><th>MRP</th><th>Equity beta</th><th>Asset beta</th><th>CoE</th></tr>
<tr><td>Prev. RP</td><td>3.27% (nominal)
1.019% (real)</td><td>5.0%</td><td>0.691</td><td>0.325</td><td>4.374%</td></tr>
<tr><td>Current RP</td><td>1.87% (nominal)
-0.19% (real)</td><td>5.0%</td><td>0.850</td><td>0.400</td><td>4.060%</td></tr>
</table>
</td></tr>
<tr><td>Method for setting the cost of debt</td><td>Ex ante (risk-free rate plus debt premium)
Current or spot estimates of the debt spread calculated as the 5-year average of corporate bond spreads of EU utilities with at least a single A rating
Bond maturities: 10 years
Time span used for assessing yields or premiums: 5 years</td></tr>
<tr><td>Inclusion of debt issuance costs</td><td>No</td></tr>
</table>

Austria

Cost of debt parameters		***Debt premium (if relevant)***	***Cost of debt (net of issuance costs)***	***Debt issuance costs (if relevant)***
	Previous regulatory period	1.45%	4.72%	N/A
	Current regulatory period	0.83%	2.70%	N/A
Gearing approach	Notional			
Gearing level	***Previous regulatory period***		60%	
	Current regulatory period		60%	
Financeability assessment	No financeability assessment			
Other regulatory mechanisms (revenue adjustments and incentives)				
Treatment of accumulated over or under-recoveries of revenues	Over and under-recoveries are adjusted between regulatory periods. Carried forward at the allowed cost of debt.			
Adjustment mechanisms for differences between forecasted or allowed operating expenditures and realised spend	No			
Adjustment mechanisms for differences between forecasted or allowed capital expenditures and realised spend	Yes (but not as an incentive mechanism – there is full reconciliation for differences between anticipated and realised investment with differences carried forward using the cost of debt)			
Treatment of capital expenditure deferrals	No distinction for deferred capital expenditure.			
Other revenue adjustment or incentive mechanisms	TSOs are measured on the following performance metrics (with weighting %): customer satisfaction (25%), unplanned availability time (25%), transparency obligations and quality of data (25%), environmental aspects (15%), and agency cooperation (10%). This is a reward-only incentive regime, up to 5% of OPEX (excluding the cost of fuel gas)			
Regulatory reporting				
Requirement for and frequency of regulatory reporting	No regulatory reporting requirement			
Coverage of regulatory reports	N/A			
Purpose of regulatory reports	N/A			
Requirement for reconciliation with audited financial statements	N/A			
Key information sources				
- NRA site: https://www.e-control.at/en/home_de - *Methodology:* https://www.e-control.at/documents/20903/388512/Methode+2017-2020+Fernleitungsnetzbetreiber+Gas_TSO_20161212.pdf/e5fa1729-efc0-ab06-06a3-2dd7088ed7c8				

16.4.2 Spain

Spain

Regulatory, market and policy framework		
Regulator	CNMC (Comisión Nacional de los Mercados y la Competencia)	
TSO(s)	▪ Enágas Transporte, S.A.U. (ENAGAS) ▪ Enágas Transporte del Norte, S.L. (ETN) ▪ Regasificadora del Noroeste, S.A. (REGANOSA) ▪ Planta de Regasificación de Sagunto, S.A. (SAGGAS)	
Customer mix	Residential/commercial	20%
	Large industrial	58%
	Power generation	22%
Ratio of transit to national flows	For 2017: 8.7% (mainly to Portugal)	
Network age and length	Pipeline length	11,152 km
	Original operation	1981
Regulatory governance and process		
Entity that establishes the methodology and sets allowed/target revenues	CNMC (NRA) Ministry of Energy, Tourism and the Digital Agenda (MINETAD)	
Length of revenue setting process	No specified time for setting allowed revenues for the duration of the regulatory period (although allowed revenue for the following year is calculated/updated annually in September-December of the previous year)	
Parties that can appeal NRA-determined revenues	TSOs	
Type of appeal that is allowed	Full merits review	
Overall framework for setting allowed revenues		
Type of regulation	Hybrid: Cost-plus, revenue cap	
Approach to assembling the cost base	Building block	
Duration of regulatory period	6 years	
Determining and setting operating expenditures		
Cost categories partially or fully passed through	Gas consumed in compression and pressure regulation stations (full pass-through)	
Methods and approaches to assessing and setting opex allowances	Top-down assessment, bottom-up assessment, trend analysis	
Inclusion of efficiency or productivity improvements	No	
Efficiency factors used in most recent regulatory period	N/A	
Treatment of gas shrinkage	TSOs hold 0.2% of transported gas for gas shrinkage purposes. If actual gas losses are higher than 0.2%, losses exceeding 0.2% are fully recognised as a cost for the TSO, valued at a market gas price. If actual losses are less than 0.2%, the TSO receives allowed revenue for half the difference at market value.	

Spain

	There is a distinction between gas losses or unaccounted for gas and operational gas. The latter is the gas consumed in compressors and regulation stations and it is recognised as a pass-through (uncontrollable expenditure cost).	
Determining and setting capital expenditures		
Methods and approaches to assessing and setting allowances	For each installation, use 'reference unit values' and the 'audited value' of the investment. Unit values are derived from a detailed project/programme review.	
Use of uncertainty mechanisms	N/A	
Inclusion of efficiency or productivity improvements	Do not use an efficiency factor but apply an efficiency philosophy by calculating the allowed capital expenditure for an asset as the average between the value calculated with reference unit costs and the value obtained from historical cost (audited value).	
Efficiency factors used in most recent regulatory period	N/A	
Use of ex post reviews before rolling capital expenditure or assets into the RAB	No	
Use of tendering for large system expansions	No	
Regulatory asset base (RAB)		
Method used for setting the opening asset value (at the time of establishing the new regulatory framework)	The historical cost of the assets as per the TSO's statutory accounts at the time	
Depreciation of closing asset value as a single asset or as separate asset categories	Asset categories depreciated individually	
Revaluation of the RAB	No	
Major assets included in the RAB	Pipelines, gas receiving stations, control stations, metering stations, SCADA stations and systems, linepack, metering and regulation stations at the interface with the distribution network, large consumer connection assets, buildings and maintenance centres	
Inclusion and treatment of linepack	A fixed quantity valued using the wholesale price index, at the time of the commissioning of the installation	
Inclusion and treatment of working capital	No	
Timing of rolling investments into the RAB	When a capital project/programme is commissioned. Financial costs incurred during the construction of the installation are included.	
Depreciation		
Method	Straight-line	
Asset lives (for major asset groupings)	Pipelines	40 years
	Compressors	20 years
	Controllers/metering stations	30 years
	SCADA, telecoms	20 years

Spain

Cost of capital and financeability	
WACC method	A financial compensation rate, equivalent to the WACC, which is determined by MINETAD The financial rate (Tr) is set directly by MINETAD (according to the calculation procedure in Law 18/2014): Tr = SB10 years + 0.5%= 5.09% Where: SB10 years = Ten-year maturity Spanish Government Bond from secondary market, calculated from 24 months before the date the 18/2014 Act came into force -July 2014-(art. 65)
WACC value set in the two most recent regulatory periods	***Previous regulatory period***: Changes each year From 2008, ranged from 7.80% to 9.67% ***Current regulatory period***: 5.09% plus extra return from 'RCS' (the amount of money that is included in the allowed revenues that serves to 'improve' the WACC)
WACC premium for specific investments or risks	No
Primary (or only) methodology for setting the cost of equity	N/A
Method for setting the risk-free rate (RFR)	N/A
Method for setting the equity or market risk premium (MRP/ERP)	N/A
Method for establishing the equity beta	N/A

WACC parameters

(RP = Regulatory Period
CoE = Cost of Equity)

	RFR	***MRP***	***Equity beta***	***Asset beta***	***CoE***
Prev. RP	N/A	N/A	N/A	N/A	N/A
Current RP	N/A	N/A	N/A	N/A	N/A

Method for setting the cost of debt	N/A
Inclusion of debt issuance costs	N/A

Cost of debt parameters

	Debt premium (if relevant)	***Cost of debt (net of issuance costs)***	***Debt issuance costs (if relevant)***
Previous regulatory period	N/A	N/A	N/A
Current regulatory period	N/A	N/A	N/A

Gearing approach	N/A

Spain

Gearing level	***Previous regulatory period***	N/A
	Current regulatory period	N/A
Financeability assessment	No	
Other regulatory mechanisms (revenue adjustments and incentives)		
Treatment of accumulated over or under-recoveries of revenues	CNMC calculates over and under-recoveries every year. As at 31 December 2014, the accumulated deficit for all TSOs (mainly coming from the previous regulatory period), was €1.025 billion. Only a part of this amount must be paid each year to the TSOs. Law 18/2014 establishes that this deficit shall be paid in 15 years, starting in 2016. Law 18/2014 also states that each new annual deficit from 2015 must be paid in 5 years (so it will be paid within the regulatory period or between regulatory periods depending on the date the deficit is recognised). For the time value of money: ▪ 1.104% for the accumulated deficit at 31 December 2014 ▪ 1.2% for each new annual deficit from 2015.	
Adjustment mechanisms for differences between forecasted or allowed <u>operating expenditures</u> and realised spend	N/A	
Adjustment mechanisms for differences between forecasted or allowed <u>capital expenditures</u> and realised spend	The asset value for the RAB is an average between actual cost (audited) and costs from applying reference unit costs, so cost savings and overspends are shared between the TSO and network users in the same way. Apply a short-term borrowing rate for the time value of money.	
Treatment of capital expenditure deferrals	As the recognised investment value for each facility is calculated as the arithmetic average between the real incurred costs (based on audited costs) and the costs calculated by using the unitary standard investment costs, any underspending or overspending is 50% shared between TSO and network users	
Other revenue adjustment or incentive mechanisms	No	
Regulatory reporting		
Requirement for and frequency of regulatory reporting	Annually	
Coverage of regulatory reports	Regulatory financial statements, technical data for the regulatory assets' database (as well as assets under construction and planned assets)	
Purpose of regulatory reports	To allow consistent assessments over time of the TSO's cost efficiency and productivity, so informing future regulatory decisions	
Requirement for reconciliation with audited financial statements	Yes	
Key information sources		
- *NRA site:* https://www.cnmc.es/ - *Methodology:* https://www.boe.es/buscar/act.php?id=BOE-A-2014-10517		

16.4.3 Finland

Finland

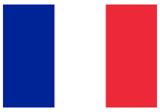
Regulatory, market and policy framework		
Regulator	Energy Authority	
TSO(s)	Gasum Oy	
Customer mix	Residential/commercial	0.9%
	Large industrial	53.1%
	Power generation	46.0%
Ratio of transit to national flows	0 (no transit)	
Network age and length	Pipeline length	1,287 km
	Original operation	1974
Regulatory governance and process		
Entity that establishes the methodology and sets allowed/target revenues	Energy Authority (NRA)	
Length of revenue setting process	24 months	
Parties that can appeal NRA-determined revenues	TSO	
Type of appeal that is allowed	Full merits review	
Overall framework for setting allowed revenues		
Type of regulation	Revenue cap / hybrid Hybrid: revenue cap for OPEX, cost-plus for capital expenditure, with several incentive mechanisms	
Approach to assembling the cost base	(A form of) building block (given that opex, capital expenditure and allowed returns are assessed separately)	
Duration of regulatory period	4 + 4 years (same methods are set for eight years, only some parameters are updated between these two periods)	
Determining and setting operating expenditures		
Cost categories partially or fully passed through	Full pass-through items include “production for own use”, balancing costs, security of supply payments, “allowances”, compressor gas	
Methods and approaches to assessing and setting opex allowances	Top-down assessment Trend analysis	
Inclusion of efficiency or productivity improvements	Yes	
Efficiency factors used in most recent regulatory period	0% per year (adjusted from 2% to account for new tasks)	
Treatment of gas shrinkage	Treated as pass-through	
Determining and setting capital expenditures		
Methods and approaches to assessing and setting allowances	*Ex post* assessment	

Finland		
Use of uncertainty mechanisms	N/A	
Inclusion of efficiency or productivity improvements	No	
Efficiency factors used in most recent regulatory period	N/A	
Use of ex post reviews before rolling capital expenditure or assets into the RAB	Yes	
Use of tendering for large system expansions	No	
Regulatory asset base (RAB)		
Method used for setting the opening asset value (at the time of establishing the new regulatory framework)	A value derived from a (current cost) accounting or valuation methodology for the underlying fixed assets of the TSO The method used is defined as “Network Present Value”. Network Present Value is calculated for every network component based on assumed average unit prices, age-information and ‘holding time’.	
Depreciation of closing asset value as a single asset or as separate asset categories	Assets depreciated individually	
Revaluation of the RAB	Yes The RAB is calculated every year using average unit prices and average age-information. Unit prices are based on realised investment costs	
Major assets included in the RAB	Pipelines, gas receiving stations, compressor stations, control stations, metering stations, metering and regulation stations at the interface with the distribution network	
Inclusion and treatment of linepack	No	
Inclusion and treatment of working capital	Working capital is included, but it is treated separately from the RAB (WACC is allowed for accounts receivables and inventories (book values), but not for cash and cash equivalents or other receivables)	
Timing of rolling investments into the RAB	Entered at book value when a capital project/programme is commissioned	
Depreciation		
Method	Straight-line	
Asset lives (for major asset groupings)	Pipelines	50-65 years
	Compressors	60 years
	Controllers/metering stations	65 years
	SCADA, telecoms	20 years
Cost of capital and financeability		
WACC method	Pre-tax, nominal	
WACC value set in the two most recent regulatory periods	***Previous regulatory period***	***Current regulatory period***
	7.39%	7.38%

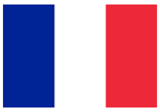
<table>
<tr><td colspan="2">
Finland</td></tr>
<tr><td>***WACC premium for specific investments or risks***</td><td>Industry specific risk premium (1.7%) for gas TSO</td></tr>
<tr><td>***Primary (or only) methodology for setting the cost of equity***</td><td>Capital Asset Pricing Model (CAPM)</td></tr>
<tr><td>***Method for setting the risk-free rate (RFR)***</td><td>10-year Finnish government bonds</td></tr>
<tr><td>***Method for setting the equity or market risk premium (MRP/ERP)***</td><td>Based on expert opinion (consulting reports and studies)</td></tr>
<tr><td>***Method for establishing the equity beta***</td><td>Based on consultant report</td></tr>
<tr><td>***WACC parameters***
(RP = Regulatory Period
CoE = Cost of Equity)</td><td><table>
<tr><td></td><td>***RFR***</td><td>***MRP***</td><td>***Equity beta***</td><td>***Asset beta***</td><td>***CoE***</td></tr>
<tr><td>***Prev. RP***</td><td>1.69%</td><td>5.0%</td><td>0.69</td><td>0.45</td><td>6.69%</td></tr>
<tr><td>***Current RP***</td><td>2.18%</td><td>5.0%</td><td>0.36</td><td>0.30</td><td>8.30%</td></tr>
</table></td></tr>
<tr><td>***Method for setting the cost of debt***</td><td>Set *ex ante* as the risk-free rate plus debt premium</td></tr>
<tr><td>***Inclusion of debt issuance costs***</td><td>No</td></tr>
<tr><td>***Cost of debt parameters***</td><td><table>
<tr><td></td><td>***Debt premium (if relevant)***</td><td>***Cost of debt (net of issuance costs)***</td><td>***Debt issuance costs (if relevant)***</td></tr>
<tr><td>***Previous regulatory period***</td><td>1.8%</td><td>3.49%</td><td>-</td></tr>
<tr><td>***Current regulatory period***</td><td>1.4%</td><td>3.58%</td><td>-</td></tr>
</table></td></tr>
<tr><td>***Gearing approach***</td><td>Notional</td></tr>
<tr><td>***Gearing level***</td><td><table>
<tr><td>***Previous regulatory period***</td><td>20%</td></tr>
<tr><td>***Current regulatory period***</td><td>40%</td></tr>
</table></td></tr>
<tr><td>***Financeability assessment***</td><td>None undertaken</td></tr>
<tr><td colspan="2">**Other regulatory mechanisms (revenue adjustments and incentives)**</td></tr>
<tr><td>***Treatment of accumulated over or under-recoveries of revenues***</td><td>Adjusted between regulatory periods</td></tr>
<tr><td>***Adjustment mechanisms for differences between forecasted or allowed <u>operating expenditures</u> and realised spend***</td><td>Incentivised through the efficiency incentive. The reward or sanction from efficiency incentive is capped at 5% (cap and floor).</td></tr>
<tr><td>***Adjustment mechanisms for differences between forecasted or allowed <u>capital expenditures</u> and realised spend***</td><td>N/A (no explicit mechanism, differences are taken into account in the surplus or deficit of the regulatory period in question)</td></tr>
<tr><td>***Treatment of capital expenditure deferrals***</td><td>N/A</td></tr>
</table>

Finland	
Other revenue adjustment or incentive mechanisms	Yes, for Energy Not Supplied (ENS) Incentive payments when ENS is in best quarter when compared to reference years (2008-2015) Penalties when in worst quarter. Dead-band in the middle. Applied symmetrically: +2%, 0%, or -2% of reasonable return for the year
Regulatory reporting	
Requirement for and frequency of regulatory reporting	Annually
Coverage of regulatory reports	Regulatory financial statements, network structure, and financial and technical key figures
Purpose of regulatory reports	To allow the NRA to prepare the decision, where the NRA confirms the amount by which the TSO's realised adjusted profit falls short of or exceeds the amount of reasonable return over the entire course of the regulatory period.
Requirement for reconciliation with audited financial statements	Yes
Key information sources	
- *NRA site:* https://www.energiavirasto.fi/home - *Methodology:* http://www.energiavirasto.fi/fi/valvontamenetelmat-2016-2023 *(Finnish)*	

16.4.4 France

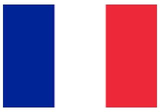
 France		
Regulatory, market and policy framework		
Regulator	Commission de régulation de l'énergie (CRE)	
TSO(s)	GRTgaz, Teréga (formerly TIGF)	
Customer mix	Residential/commercial (and small industrial connected to distribution networks)	59.6%
	Large industrial	29.1%
	Power generation	11.3%
Ratio of transit to national flows	0.34 (average ratio of Teréga and GRTgaz, weighted by their 2016 total consumption numbers)	
Network age and length	Pipeline length	37,596 km (including regional networks)
	Original operation	The first assets were commissioned 50 years ago. The estimated average age (weighted by their net accounting value) of the transmission assets is roughly 12 years.
Regulatory governance and process		
Entity that establishes the methodology and sets allowed/target revenues	CRE (the NRA) develops the methodology and sets the allowed revenue. The methodology might be reviewed and amended by the government (only if the methodology does not take into account government energy policy guidelines) and 'Conseil d'Etat' (the top administrative court) if the methodology is challenged by a stakeholder	
Length of revenue setting process	Approximately 18 months	
Parties that can appeal NRA-determined revenues	TSO, transmission system users, any stakeholders	
Type of appeal that is allowed	Limited merits / full merits / procedural review	
Overall framework for setting allowed revenues		
Type of regulation	Hybrid: revenue cap for OPEX, cost-plus for capital expenditure, with several incentive mechanisms	
Approach to assembling the cost base	Building blocks	
Duration of regulatory period	Four years	
Determining and setting operating expenditures		
Cost categories partially or fully passed through	Partial pass-through: quality conversion (L-Gas, H-Gas, volume effect) Full pass-through: connection revenues, inter-TSO contracts and ITC, congestion relief costs (eg flow commitments), compensation between TSOs	
Methods and approaches to assessing and setting opex allowances	Bottom-up assessment, trend analysis and TOTEX (for IT, vehicles and buildings)	

France	
Inclusion of efficiency or productivity improvements	Yes
Efficiency factors used in most recent regulatory period	CPI + 0.74% (GRTgaz) / CPI+1.04% (Teréga)
Treatment of gas shrinkage	Partial pass-through: 80%of the difference between allowed and actual losses
Determining and setting capital expenditures	
Methods and approaches to assessing and setting allowances	Bottom-up assessment, detailed project/programme reviews (for all cost categories), business case analysis (for major developments), TOTEX (for IT, vehicles and buildings)
Use of uncertainty mechanisms	A budget ceiling is sometimes placed on certain investments (this budget ceiling/target is used to encourage TSOs' cost efficiency. Specifically, if the actual cost of a specific project exceeds the budget ceiling, the whole actual cost would still be logged into the RAB but the remuneration rate applied to this specific project would be decreased)
Inclusion of efficiency or productivity improvements	No
Efficiency factors used in most recent regulatory period	N/A
Use of ex post reviews before rolling capital expenditure or assets into the RAB	Annual review, plus specific monitoring of major projects (those greater than €20m)
Use of tendering for large system expansions	Yes, for all asset types
Regulatory asset base (RAB)	
Method used for setting the opening asset value (at the time of establishing the new regulatory framework)	Established by a commission headed by the academic Houri, but the methodology employed is not public. In summary, however, this entailed the following: The historic value of the operator's assets was based on a "current economic costs" method defined by the Special Commission instituted by Article 81 of the amended finance law of 28 December 2001, tasked with setting the price of disposal, by the French State, of its natural gas transmission networks. Therefore, assets brought into service before 31 December 2001 were valued by means of adjusting the historical costs for inflation, using the following method: ▪ historical gross asset values were adjusted for the revaluation variances permitted in 1976, subsidies received in respect of carrying out these investments, and contributions received from the beneficiaries of these investments; ▪ these restated gross values were re-valued as at 31 December 2002 by applying the "market-sector GDP" price index; ▪ these adjusted gross values were then depreciated using the straight-line method on the basis of the economic lifespan of the various asset categories. Assets are deemed to have become operational on 1 July of the year.
Depreciation of closing asset value as a single asset or as separate asset categories	Assets are depreciated individually
Revaluation of the RAB	No (although the RAB is indexed for inflation given the use of a



<table>
<tr><td colspan="7">France</td></tr>
<tr><td></td><td colspan="6">real WACC)</td></tr>
<tr><td>Major assets included in the RAB</td><td colspan="6">Pipelines, gas receiving stations, compressor stations, control stations, metering stations, SCADA stations and systems, metering and regulation stations at the interface with the distribution network, some large consumer connection assets</td></tr>
<tr><td>Inclusion and treatment of linepack</td><td colspan="6">No</td></tr>
<tr><td>Inclusion and treatment of working capital</td><td colspan="6">No</td></tr>
<tr><td>Timing of rolling investments into the RAB</td><td colspan="6">When a capital project/programme is commissioned.
At their commissioning, assets are logged into the RAB at the gross accounting value. Financing costs are covered during the construction phase using the allowed cost of debt.</td></tr>
<tr><td colspan="7">Depreciation</td></tr>
<tr><td>Method</td><td colspan="6">Straight-line</td></tr>
<tr><td rowspan="4">Asset lives (for major asset groupings)</td><td colspan="3">Pipelines</td><td colspan="3">50 years</td></tr>
<tr><td colspan="3">Compressors</td><td colspan="3">30 years</td></tr>
<tr><td colspan="3">Controllers/metering stations</td><td colspan="3">30 years</td></tr>
<tr><td colspan="3">SCADA, telecoms</td><td colspan="3">10 years</td></tr>
<tr><td colspan="7">Cost of capital and financeability</td></tr>
<tr><td>WACC method</td><td colspan="6">Pre-tax, real</td></tr>
<tr><td rowspan="2">WACC value set in the two most recent regulatory periods</td><td colspan="3">Previous regulatory period</td><td colspan="3">Current regulatory period</td></tr>
<tr><td colspan="3">6.50%</td><td colspan="3">5.25%</td></tr>
<tr><td>WACC premium for specific investments or risks</td><td colspan="6">Yes, for some specific major projects.
Set to 3% during the previous regulatory period for 10 years for major projects (IP developments or market zone mergers). No WACC premium has been set in the current regulatory period.</td></tr>
<tr><td>Primary (or only) methodology for setting the cost of equity</td><td colspan="6">Capital Asset Pricing Model (CAPM)</td></tr>
<tr><td>Method for setting the risk-free rate (RFR)</td><td colspan="6">Long-term bonds: typically, the average of 10- to 30-year bonds over the past 10 years</td></tr>
<tr><td>Method for setting the equity or market risk premium (MRP/ERP)</td><td colspan="6">Using an arithmetic average, MRP is set according to DMS (average European index) and other considerations. MRP is added to the RFR to estimate total market returns.</td></tr>
<tr><td>Method for establishing the equity beta</td><td colspan="6">Evaluated according to the market betas of European listed TSOs such as Fluxys (Belgium), Enagas (Spain), National Grid (UK) over 3-5 years of daily observations. Also, sense-checked against other regulatory precedents</td></tr>
<tr><td rowspan="3">WACC parameters
(RP = Regulatory Period
CoE = Cost of Equity)</td><td></td><td>RFR (real)</td><td>MRP</td><td>Equity beta</td><td>Asset beta</td><td>CoE (pre-tax)[80]</td></tr>
<tr><td>Prev. RP</td><td>2.0%</td><td>5.0%</td><td>0.96</td><td>0.58</td><td>10.4%</td></tr>
<tr><td>Current RP</td><td>1.6%</td><td>5.0%</td><td>0.75</td><td>0.45</td><td>8.1%</td></tr>
</table>

[80] A tax rate of 34.43% is applied to the after-tax cost of equity.



France				
Method for setting the cost of debt	RFR plus debt premium. Set *ex ante* as a combination of historical interest costs and current spot estimates			
Inclusion of debt issuance costs	No			
Cost of debt parameters		***Debt premium (if relevant)***	***Cost of debt (net of issuance costs), real***	***Debt issuance costs (if relevant)***
	Previous regulatory period	0.6%	2.6%	-
	Current RP	0.6%	2.4%	-
Gearing approach	Notional			
Gearing level	***Previous regulatory period***	50%		
	Current regulatory period	50%		
Financeability assessment	No			
Other regulatory mechanisms (revenue adjustments and incentives)				
Treatment of accumulated over or under-recoveries of revenues	Adjusted between regulatory periods. Over- and under-recoveries calculated annually. Reconciled over the next four years at present value, using the risk-free rate as the discount rate.			
Adjustment mechanisms for differences between forecasted or allowed operating expenditures and realised spend	No, efficiency gains or cost over-runs are retained and incurred for the regulatory period			
Adjustment mechanisms for differences between forecasted or allowed capital expenditures and realised spend	Generally, not – there is a scheme only for large (>€20m projects), as stated below			
Treatment of capital expenditure deferrals	Only for investments needed to merge zones or markets - the remuneration rate can be reduced in case of an undue delay			
Other revenue adjustment or incentive mechanisms	Yes, various schemes: ▪ Quality of service (16 metrics) ▪ Incentive mechanism to reduce investment costs (for projects above €20 m) with a premium or a penalty when the actual cost differs significantly from the budgeted cost ▪ Research and development(cap) ▪ Regulatory account with specific coverage rate for various categories of revenues and expenditures ▪ Periodic review clause (if the allowed level of OPEX is altered by at least 1% by a legislative, legal or regulatory decision). Possibility to start a new regulatory period after two years			
Regulatory reporting				
Requirement for and frequency of regulatory reporting	Annually			
Coverage of regulatory reports	Regulatory financial statements, financial submissions			
Purpose of regulatory reports	To allow the NRA to calculate the applicable adjustments to apply to allowed revenues in the following regulatory period because of differences between actual and forecast outcomes in			

France	
	the current period. To monitor the TSO's investments and their compliance with the TYNPD and the yearly plan.
Requirement for reconciliation with audited financial statements	No
Key information sources	
- *NRA site: http://www.cre.fr/*	

16.4.5 Hungary

Hungary		
Regulatory, market and policy framework		
Regulator	Hungarian Energy and Public Utility Regulatory Authority	
TSO(s)	FGSZ Natural Gas Transmission Closed Company Limited by Shares (FGSZ) Hungarian Gas Transit Ltd. (MGT)	
Customer mix	Residential/commercial	52.0%
	Large industrial	22.8%
	Power generation	25.2%
Ratio of transit to national flows	0.291	
Network age and length	Pipeline length	5,874 km
	Original operation	1949 – first gas transmission on a gas/oil transmission pipeline 1958 – first dedicated gas transmission pipeline
Regulatory governance and process		
Entity that establishes the methodology and sets allowed/target revenues	Hungarian Energy and Public Utility Regulatory Authority	
Length of revenue setting process	2-3 months	
Parties that can appeal NRA-determined revenues	None	
Type of appeal that is allowed	N/A	
Overall framework for setting allowed revenues		
Type of regulation	Hybrid: Could be characterised as 'cost-based regulation with incentives'. An annual correction is applied based on outturn costs compared to revenues set at the beginning of the period, however, the profit of the TSO is capped.	
Approach to assembling the cost base	Building block approach	
Duration of regulatory period	4 years	
Determining and setting operating expenditures		
Cost categories partially or fully passed through	Items such as local taxes or administrative charges are passed through	
Methods and approaches to assessing and setting opex allowances	Bottom-up assessment, benchmarking (only used for employee expenditures and office rental costs), trend analysis (volume-related costs, technical losses) More generally, outturn opex in the last available year (the penultimate year of the previous regulatory period) is taken as the 'base opex' for setting allowances in the next period. The 'base opex' is then adjusted by an inflation index (CPI) and an efficiency factor (see below).	
Inclusion of efficiency or productivity improvements	Yes	

Hungary	
Efficiency factors used in most recent regulatory period	1.5%/year
Treatment of gas shrinkage	The acknowledged volume of technical losses is set by the NRA. The price of losses is also regulated. Two main categories: TSO's own gas consumption and technical losses.
Determining and setting capital expenditures	
Methods and approaches to assessing and setting allowances	Bottom-up assessments/unit cost analysis. The usage of the assets is also considered when undertaking period revaluations of the RAB.
Use of uncertainty mechanisms	No
Inclusion of efficiency or productivity improvements	No
Efficiency factors used in most recent regulatory period	N/A
Use of ex post reviews before rolling capital expenditure or assets into the RAB	No
Use of tendering for large system expansions	Yes, purchases subject to public procurement
Regulatory asset base (RAB)	
Method used for setting the opening asset value (at the time of establishing the new regulatory framework)	A value derived from a (current cost) accounting or valuation methodology for the underlying fixed assets of the TSO – replacement cost methodology
Depreciation of closing asset value as a single asset or as separate asset categories	Assets depreciated individually
Revaluation of the RAB	Yes, using a replacement cost methodology
Major assets included in the RAB	Pipelines, gas receiving stations, compressor stations, control stations, metering stations, SCADA stations and systems, linepack, metering and regulation stations at the interface with the distribution network, large consumer connection assets, telecommunication network
Inclusion and treatment of linepack	A fixed quantity Value calculated by the TSO
Inclusion and treatment of working capital	No
Timing of rolling investments into the RAB	When commissioned is the default, although capex spend as incurred is sometimes allowed for large investments (to facilitate funding of those investments)
Depreciation	
Method	Straight-line
Asset lives (for major asset groupings)	Pipelines: 50 years Compressors: 20 years Controllers/metering stations: 20 years SCADA, telecoms: 25 years

<table>
<tr><td colspan="2">Hungary</td></tr>
<tr><td colspan="2">Cost of capital and financeability</td></tr>
<tr><td>WACC method</td><td>Pre-tax, real</td></tr>
<tr><td>WACC value set in the two most recent regulatory periods</td><td><table><tr><td>Previous regulatory period</td><td>Current regulatory period</td></tr><tr><td>8.78%</td><td>4.62%</td></tr></table></td></tr>
<tr><td>WACC premium for specific investments or risks</td><td>No</td></tr>
<tr><td>Primary (or only) methodology for setting the cost of equity</td><td>Capital Asset Pricing Model (CAPM)</td></tr>
<tr><td>Method for setting the risk-free rate (RFR)</td><td>US 10Y government bonds + country risk (historical trend of CDS spread)</td></tr>
<tr><td>Method for setting the equity or market risk premium (MRP/ERP)</td><td>Historical data (Dimson, Marsh, and Staunton) reflecting actual investment returns over time.
Add MRP estimate (calculated as an arithmetic average) to RFR to estimate total market return.</td></tr>
<tr><td>Method for establishing the equity beta</td><td>Calculated with the local stock market index and a list of regulated company stocks over a 1-4 year period.</td></tr>
<tr><td>WACC parameters
(RP = Regulatory Period
CoE = Cost of Equity)</td><td><table><tr><td></td><td>RFR</td><td>MRP</td><td>Equity beta</td><td>Asset beta</td><td>CoE</td></tr><tr><td>Prev. RP</td><td>3.89%</td><td>6.6%</td><td>0.74</td><td>-</td><td>8.11%</td></tr><tr><td>Current RP</td><td>1.88%</td><td>4.3%</td><td>0.72</td><td>-</td><td>4.97%</td></tr></table></td></tr>
<tr><td>Method for setting the cost of debt</td><td>Set ex ante as the risk-free rate plus a debt premium, based on Fitch, Moody's, and S&P spot estimates of debt costs for the TSO.</td></tr>
<tr><td>Inclusion of debt issuance costs</td><td>No</td></tr>
<tr><td>Cost of debt parameters</td><td><table><tr><td></td><td>Debt premium (if relevant)</td><td>Cost of debt (net of issuance costs)</td><td>Debt issuance costs (if relevant)</td></tr><tr><td>Previous regulatory period</td><td>1.8%</td><td>5.69%</td><td>n/a</td></tr><tr><td>Current regulatory period</td><td>1.4%</td><td>3.27%</td><td>n/a</td></tr></table></td></tr>
<tr><td>Gearing approach</td><td>Notional, set at European benchmark value</td></tr>
<tr><td>Gearing level</td><td><table><tr><td>Previous regulatory period</td><td>40%</td></tr><tr><td>Current regulatory period</td><td>53%</td></tr></table></td></tr>
<tr><td>Financeability assessment</td><td>No</td></tr>
<tr><td colspan="2">Other regulatory mechanisms (revenue adjustments and incentives)</td></tr>
<tr><td>Treatment of accumulated over or under-recoveries of revenues</td><td>A profit sharing mechanism is used, irrespective of the cause of over-recovery (see other mechanisms below)</td></tr>
<tr><td>Adjustment mechanisms for differences between forecasted or allowed <u>operating expenditures</u> and realised spend</td><td>A profit sharing mechanism is used, irrespective of the cause of over-recovery (see other mechanisms below)</td></tr>
</table>

Hungary	
Adjustment mechanisms for differences between forecasted or allowed capital expenditures and realised spend	A profit sharing mechanism is used, irrespective of the cause of over-recovery (see other mechanisms below)
Treatment of capital expenditure deferrals	No special treatment
Other revenue adjustment or incentive mechanisms	The approach used can be characterised as 'asymmetrical earnings sharing', that is, if the TSO earns profits above those allowed, then 50% of the difference 'may' be shared with network users, but there is no adjustment for lower profits than those allowed. Although the mechanism does not necessarily apply automatically, the Authority has always made adjustments in practice.
Regulatory reporting	
Requirement for and frequency of regulatory reporting	No
Coverage of regulatory reports	N/A
Purpose of regulatory reports	N/A
Requirement for reconciliation with audited financial statements	N/A
Key information sources	
- *NRA site: http://www.mekh.hu/* - *Methodology: http://mekh.hu/download/a/1a/20000/modszertani_utmutato_foldgaz_ii.pdf*	

16.4.6 Italy

Italy

Regulatory, market and policy framework	
Regulator	Autorità di Regolazione per Energia Reti e Ambiente (ARERA)
TSO(s)	Various TSOs: ▪ Consorzio della Media Valtellina per il Trasporto del Gas ▪ Energie Rete Gas S.r.l. ▪ GP Infrastrutture Trasporto S.r.l. ▪ Infrastrutture Trasporto Gas S.p.a (recently acquired by Snam Rete Gas) ▪ Metanodotto Alpino S.r.l. ▪ Netenergy Service S.r.l. ▪ Retragas S.r.l. ▪ SGI S.p.a. ▪ Snam Rete Gas S.p.a. However, the most significant TSO is Snam Rete Gas S.p.a. It owns more than 95% of the entire network.
Customer mix	Residential/commercial: 45% Large industrial: 20% Power generation: 35%
Ratio of transit to national flows	
Network age and length	Pipeline length: 34 200 km of which 32 300 is owned by Snam Rete gas Original operation: 1959
Regulatory governance and process	
Entity that establishes the methodology and sets allowed/target revenues	ARERA (NRA)
Length of revenue setting process	2 months
Parties that can appeal NRA-determined revenues	The TSO and transmission system users can appeal the decision
Type of appeal that is allowed	Limited merits and procedural review
Overall framework for setting allowed revenues	
Type of regulation	Cost plus for capital expenditure with a price cap for operating expenditure
Approach to assembling the cost base	Building block approach
Duration of regulatory period	4 Years
Determining and setting operating expenditures	
Cost categories partially or fully passed through	Fully passed through: fuel costs and 'operational balance costs'
Methods and approaches to assessing and setting opex allowances	At the beginning of each regulatory period allowed opex allowances are aligned to actual opex expenditure, net of: ▪ A profit sharing mechanism, if efficiency targets have been

Italy

	met ▪ - A loss sharing mechanism, if efficiency targets have not been met	
Inclusion of efficiency or productivity improvements	Yes	
Efficiency factors used in most recent regulatory period	1.3% per year (this is an average for the sector, as company-specific factors are set)	
Treatment of gas shrinkage	Gas shrinkage is costed at the standard value of gas used in addition to the cost of a mandatory substitution plan for network components (to be implemented)	
Determining and setting capital expenditures		
Methods and approaches to assessing and setting allowances	*Ex ante* business case analysis is required as part of the process of developing a National Development Plan	
Use of uncertainty mechanisms	No	
Inclusion of efficiency or productivity improvements	No	
Efficiency factors used in most recent regulatory period	N/A	
Use of ex post reviews before rolling capital expenditure or assets into the RAB	Yes, where there are significant costs overruns ie these are optional and depend on the materiality of the project (not yet conducted for gas transmission but can be undertaken by ARERA at its discretion)	
Use of tendering for large system expansions	The TSO must comply with procurement rules.	
Regulatory asset base (RAB)		
Method used for setting the opening asset value (at the time of establishing the new regulatory framework)	The historical cost of the assets ie the depreciated book value of the assets as per the TSO's statutory accounts at the time	
Depreciation of closing asset value as a single asset or as separate asset categories	Asset categories are depreciated individually	
Revaluation of the RAB	No	
Major assets included in the RAB	Major assets in the RAB include metering stations, compressor stations, metering and regulation stations, buildings, land, IT	
Inclusion and treatment of linepack	Included in the RAB, as an increase of the value of the pipeline assets (hence it is depreciated over time). The value of the pipeline asset, then, comprises both the pipe and the gas inside the pipe. The value of the gas is the actual price paid by the TSO	
Inclusion and treatment of working capital	Working capital is included in the RAB. It is assumed to be 0.8% of the gross investment capital	
Timing of rolling investments into the RAB	Assets are included in the RAB as investment is incurred	
Depreciation		
Method	Straight line depreciation	
Asset lives (for major asset groupings)	Pipelines	50

Italy

	Compressors	20
	Controllers/metering stations	20
	SCADA, telecoms	5
Cost of capital and financeability		
WACC method	Pre-tax WACC set in real terms	
WACC value set in the two most recent regulatory periods	***Previous regulatory period***	***Current regulatory period***
	5.4% (2016/2017)	5.4% (2018)

WACC premium for specific investments or risks	Yes, a WACC premium is applied for investments that increase network capacity. For investments which enter operation in 2018 and 2019 and increase network transmission capacity there is an increased premium of +1% for 12 years.
Primary (or only) methodology for setting the cost of equity	Capital Asset Pricing Model (CAPM)
Method for setting the risk-free rate (RFR)	Based on the historical yields of other government bonds. Currently, average yields of France, Belgium, Netherlands and Germany bonds (10 years), as long as they have maintained a rating level of at least AA according to S&P's classification for the period 1st October 2017 – 30th September 2018.
Method for setting the equity or market risk premium (MRP/ERP)	The MRP is based on actual returns over a period of time. It was computed as the difference between the rate of Total Market Return (TMR) and the real Risk-Free Rate (RFR). TMR represents the market's total return and it is computed as a weighted average of the historical data of returns in four countries with AA S&P rating (Belgium, France, Germany, the Netherlands) over the period 1900-2014. In the TMR computation, a combination of arithmetic and geometric average is used (respectively, 80% and 20%). A Country Risk Premium (CRP) for Italy is also added, which is computed by estimating the difference between the yields of bonds issued by Italian utilities and the yields of bonds issued by utilities based in Eurozone high-rated countries. This parameter is then adjusted with the volatility of the Italian stock market. Currently, CRP is set to 1%.
Method for establishing the equity beta	By calculation based on regulated company stocks from various EU countries (Fluxys, Snam Rete Gas, REN - Gasodutos, S.A., Enagas S.A., National Grid). The estimation period was fur years.

		RFR	***MRP***	***Equity beta***	***Asset beta***	***CoE***
WACC parameters *(RP = Regulatory Period* *CoE = Cost of Equity)*	***Prev. RP (14-17)***	4.41% (2014-15) 0.79% nominal 0.5% real (2016-17)	4.00% (2014-15) 5.5% (2016-17)	0.575	0.364	4.9% (2014-15) 3.5% (2016-17)

Italy

<table>
<tr><td></td><td>Current RP (18/19)</td><td>0.79% nominal
0.5% real</td><td>5.5%</td><td>0.575 (2018)
To be updated in 2019 taking into account updated tax shield</td><td>0.364</td><td>3.5% (2018)
To be updated in 2019 according to updated value of tax shield</td></tr>
<tr><td>Method for setting the cost of debt</td><td colspan="6">Debt costs are determined in advance and are by reference to the specific TSO and comparator companies to the TSO.
The cost of debt is defined by applying a spread (Debt Risk Premium, DRP) to the RFR, and by adding the term CPR described earlier. The computation is based on data from a representative sample of firms operating in the energy infrastructure (gas and electricity) sector.</td></tr>
<tr><td>Inclusion of debt issuance costs</td><td colspan="6">No</td></tr>
<tr><td rowspan="3">Cost of debt parameters</td><td></td><td colspan="2">Debt premium (if relevant)</td><td colspan="2">Cost of debt (net of issuance costs)</td><td>Debt issuance costs (if relevant)</td></tr>
<tr><td>Previous regulatory period</td><td colspan="2">0.45% (2014-15)
0.5%
(2016-17)</td><td colspan="2">4.86% (2014-15)
2%
(2016-17)</td><td>n/a</td></tr>
<tr><td>Current regulatory period</td><td colspan="2">0.5%</td><td colspan="2">2%</td><td>n/a</td></tr>
<tr><td>Gearing approach</td><td colspan="6">Notional</td></tr>
<tr><td rowspan="2">Gearing level</td><td colspan="3">Previous regulatory period</td><td colspan="3">44.4%</td></tr>
<tr><td colspan="3">Current regulatory period</td><td colspan="3">44.4%</td></tr>
<tr><td>Financeability assessment</td><td colspan="6">N/A</td></tr>
<tr><td colspan="7">Other regulatory mechanisms (revenue adjustments and incentives)</td></tr>
<tr><td>Treatment of accumulated over or under-recoveries of revenues</td><td colspan="6">Tariffs are adjusted within period as well as over periods to take into account under and over recoveries through the ‘reconciliation process’. Reconciliation takes place through tariff adjustments in year ‘y+2’. To avoid steep tariff changes, if the reconciliation is more than 2% of allowed revenues, the amount of reconciliation exceeding that threshold is split over four years. Where over or under recoveries are moved to a different year then a risk free rate plus a premium is applied.</td></tr>
<tr><td>Adjustment mechanisms for differences between forecasted or allowed <u>operating expenditures</u> and realised spend</td><td colspan="6">A profit sharing mechanism is in place whereby, if during a regulatory period an operator reduces its opex, the allowed opex for the next regulatory period is set as to recover actual operating costs plus a decreasing share of half the efficiency gains obtained during the previous period (over 8 years). Efficiency gains are defined as the difference between allowed opex (net of profit sharing) and actual costs in the last year of the regulatory period.</td></tr>
</table>

Italy

	A similar mechanism is in place where actual opex is higher than allowed opex.
Adjustment mechanisms for differences between forecasted or allowed capital expenditures and realised spend	Not applicable – cost-plus approach used for capital expenditure
Treatment of capital expenditure deferrals	None
Other revenue adjustment or incentive mechanisms	No
Regulatory reporting	
Requirement for and frequency of regulatory reporting	Annual regulatory reporting statements required
Coverage of regulatory reports	The regulatory statements are financial submissions which include financial statements and details ie actual expenditure to forecast expenditure. Furthermore, the TSOs submits any relevant network investment plans.
Purpose of regulatory reports	They allow the NRA to receive consistent assessment of the TSOs' cost efficiency and productivity. Furthermore, the NRA is also able to comprehensively gather information on future adjustments for the next regulatory period by assessing how allowances vary from actual spend.
Requirement for reconciliation with audited financial statements	Yes
Key information sources	
Provide links for: - *TSO: http://www.snam.it/en* - *NRA: https://www.arera.it/*	

16.4.7 Lithuania

Lithuania

Regulatory, market and policy framework		
Regulator	National Commission for Energy and Prices	
TSO(s)	Amber Grid (AB)	
Customer mix	Residential/commercial	25%
	Large industrial	74%
	Power generation	1%
Ratio of transit to national flows		
Network age and length	Pipeline length	2,113 km
	Original operation	1961
Regulatory governance and process		
Entity that establishes the methodology and sets allowed/target revenues	National Commission for Energy and Prices	
Length of revenue setting process	2 months	
Parties that can appeal NRA-determined revenues	All parties can appeal the decision	
Type of appeal that is allowed	A full merit review is allowed	
Overall framework for setting allowed revenues		
Type of regulation	Hybrid	
Approach to assembling the cost base	Based on a building blocks approach	
Duration of regulatory period	5 years	
Determining and setting operating expenditures		
Cost categories partially or fully passed through	Taxes are full pass-through costs whereas unscheduled maintenance work constitutes partial cost pass-through	
Methods and approaches to assessing and setting opex allowances	Both a top-down and a bottom-up approach are used to calculate the opex allowances. Trend analysis is used to verify and challenge costs	
Inclusion of efficiency or productivity improvements	Yes	
Efficiency factors used in most recent regulatory period	1%	
Treatment of gas shrinkage	Only technical losses recognised and these cannot be higher than 3 per cent of the transported gas volumes	
Determining and setting capital expenditures		
Methods and approaches to assessing and setting allowances	Capital expenditure allowances are set based on a bottom-up assessment of required investment. Investments are approved based on detailed project reviews and business cases presented to the NRA	

Lithuania

Use of uncertainty mechanisms	For certain projects where costs are not certain, or thresholds are exceeded by 10% the project can be reviewed by the Regulator. The approach is known as '*logging up*'	
Inclusion of efficiency or productivity improvements	No, not considered for capital expenditure	
Efficiency factors used in most recent regulatory period	N/A	
Use of ex post reviews before rolling capital expenditure or assets into the RAB	No	
Use of tendering for large system expansions	Yes, for each long-term expansion (gas distribution stations, pipelines, metering stations, etc) competitive tendering is required	
Regulatory asset base (RAB)		
Method used for setting the opening asset value (at the time of establishing the new regulatory framework)	Based on the historical cost of the assets ie the depreciated book value of the assets as per the TSO's statutory accounts at the time	
Depreciation of closing asset value as a single asset or as separate asset categories	Asset categories are depreciated individually	
Revaluation of the RAB	The RAB is not periodically revalued	
Major assets included in the RAB	Major assets include pipelines, gas receiving stations, compressor stations, SCADA stations and systems, gas storage assets, metering and regulation stations, line pack and large customer connection assets	
Inclusion and treatment of linepack	Included in the RAB, but non-depreciable	
Inclusion and treatment of working capital	Working capital is not included in the RAB	
Timing of rolling investments into the RAB	Assets are added into the RAB when they are commissioned but there is no allowance to account for financing costs	
Depreciation		
Method	Straight-line depreciation	
Asset lives (for major asset groupings)	Pipelines	55
	Compressors	20
	Controllers/metering stations	9
	SCADA, telecoms	4
Cost of capital and financeability		
WACC method	Pre-tax nominal	
WACC value set in the two most recent regulatory periods	***Previous regulatory period***	***Current regulatory period***
	8.05% (2009, 2012, 2013); 5,0% (2010, 2011)	7.09%
WACC premium for specific investments or risks	No, a premium is not allowed	

Lithuania

<table>
<tr><td colspan="2">Primary (or only) methodology for setting the cost of equity</td><td colspan="5">The Capital Asset Pricing Model (CAPM)</td></tr>
<tr><td colspan="2">Method for setting the risk-free rate (RFR)</td><td colspan="5">Calculated on the basis of government bonds. The arithmetic mean of the average weighted profitability of the auctions of the Lithuania Government bonds denominated in Litas (till December 31,2014) and Euros (from January 1, 2015) with the maturity period of no less than 3,468 days), held during the recent ten-year period.</td></tr>
<tr><td colspan="2">Method for setting the equity or market risk premium (MRP/ERP)</td><td colspan="5">The MRP is calculated as an arithmetic average, and is set as the sum of the equity risk premium of the US and the additional market risk premium of Lithuania (last 20 years).
The US equity risk premium is defined as the difference between the return on investments in the US stock market during the last 20 years (on the basis of the S&P 500 index), and the rate of return on US treasury bonds with a 10-year maturity (based on data for US treasury bonds announced by the bank of the US Federal Reserve System).
The additional market risk premium of Lithuania is determined as the difference between the risk ratio (in per cent) corresponding to the credit rating of Lithuania and the risk ratio (in per cent) corresponding to the US credit rating, using the data of professor A. Damodaran.</td></tr>
<tr><td colspan="2">Method for establishing the equity beta</td><td colspan="5">Established by calculation and precedent, namely the arithmetic average of the beta of the gas transmission sector of the EU countries presented in the Annual Report on the Investment Conditions of the European Energy Regulators Council (CEER)</td></tr>
<tr><td colspan="2" rowspan="3">WACC parameters
(RP = Regulatory Period
CoE = Cost of Equity)</td><td></td><td>RFR</td><td>MRP</td><td>Equity beta</td><td>Asset beta / CoE</td></tr>
<tr><td>Prev. RP</td><td>4.36</td><td>5.59</td><td>0.9</td><td> / 6.87%</td></tr>
<tr><td>Current RP</td><td>4.2</td><td>5.63</td><td>0.42</td><td> / 11.3%</td></tr>
<tr><td colspan="2">Method for setting the cost of debt</td><td colspan="5">Ex-ante setting of the cost of debt based on historical interest costs using market data</td></tr>
<tr><td colspan="2">Inclusion of debt issuance costs</td><td colspan="5">No</td></tr>
<tr><td colspan="2" rowspan="3">Cost of debt parameters</td><td></td><td>Debt premium (if relevant)</td><td>Cost of debt (net of issuance costs)</td><td colspan="2">Debt issuance costs (if relevant)</td></tr>
<tr><td>Previous regulatory period</td><td>n/a</td><td>5.34%</td><td colspan="2">n/a</td></tr>
<tr><td>Current regulatory period</td><td>n/a</td><td>4.43%</td><td colspan="2">n/a</td></tr>
<tr><td colspan="2">Gearing approach</td><td colspan="5">Notional</td></tr>
<tr><td colspan="2" rowspan="2">Gearing level</td><td colspan="2">Previous regulatory period</td><td colspan="3">1.2%</td></tr>
<tr><td colspan="2">Current regulatory period</td><td colspan="3">70%</td></tr>
<tr><td colspan="2">Financeability assessment</td><td colspan="5">Financeability assessments are conducted to take into account:</td></tr>
</table>

Lithuania

	▪ Net debt/RAB ie the liability to asset ratio ▪ Funds from operations that cover interest (FFO) ▪ FFO/Net debt If the TSO was not deemed to be financeable then NCC would have to review the WACC.
Other regulatory mechanisms (revenue adjustments and incentives)	
Treatment of accumulated over or under-recoveries of revenues	Adjusted within and between regulatory periods. Over and under-recoveries are assessed in the third and fifth years of the regulatory period. Under and over recoveries are carried forward using the cost of debt
Adjustment mechanisms for differences between forecasted or allowed <u>operating expenditures</u> and realised spend	None
Adjustment mechanisms for differences between forecasted or allowed <u>capital expenditures</u> and realised spend	None
Treatment of capital expenditure deferrals	None
Other revenue adjustment or incentive mechanisms	No
Regulatory reporting	
Requirement for and frequency of regulatory reporting	Yes, regulatory statements are submitted annually. NCC also receives unaudited accounts on a quarterly basis.
Coverage of regulatory reports	The AB Grid is required to submit regulatory financial statements and financial submissions (including indicators of financial strength)
Purpose of regulatory reports	Regulatory reports allow assessment against forecast outcomes, allow an opportunity to review productivity and cost efficiency, and to understand what adjustments might be required in future regulatory periods based on differences in actual and forecast outcomes
Requirement for reconciliation with audited financial statements	No, the financial and regulatory statements are not the same
Key information sources	

16.4.8 Latvia

Latvia		
Regulatory, market and policy framework		
Regulator	The Public Utilities Commission (PUC)	
TSO(s)	JSC Conexus Baltic Grid	
Customer mix	Residential/commercial	24%
	Large industrial	8%
	Power generation	68%
Ratio of transit to national flows	0.11	
Network age and length	Pipeline length	1,191 km
	Original operation	1966
Regulatory governance and process		
Entity that establishes the methodology and sets allowed/target revenues	The Public Utilities Commission (PUC)	
Length of revenue setting process	3 months	
Parties that can appeal NRA-determined revenues	TSO, transmission system users, any stakeholders	
Type of appeal that is allowed	Limited merits, full merits, and procedural review	
Overall framework for setting allowed revenues		
Type of regulation	Hybrid - revenue cap for opex and (mostly) cost-plus for capital expenditure	
Approach to assembling the cost base	Building block approach	
Duration of regulatory period	1 year	
Determining and setting operating expenditures		
Cost categories partially or fully passed through	Unforeseen costs that can be demonstrated to arise from changes in legislation or emergency situations and insofar as they cannot be recovered otherwise	
Methods and approaches to assessing and setting opex allowances	Bottom-up assessment, trend analysis	
Inclusion of efficiency or productivity improvements	No	
Efficiency factors used in most recent regulatory period	N/A	
Treatment of gas shrinkage	Gas losses are evaluated based on historical data and based on company information about forecasted possible changes which could increase/decrease gas losses. Loss categories: technical, commercial, shrinkage.	
Determining and setting capital expenditures		
Methods and approaches to assessing and setting allowances	No *ex ante* assessment	

Latvia

Use of uncertainty mechanisms	No	
Inclusion of efficiency or productivity improvements	No	
Efficiency factors used in most recent regulatory period	N/A	
Use of ex post reviews before rolling capital expenditure or assets into the RAB	No	
Use of tendering for large system expansions	Yes, for all fixed assets	
Regulatory asset base (RAB)		
Method used for setting the opening asset value (at the time of establishing the new regulatory framework)	Replacement cost methodology	
Depreciation of closing asset value as a single asset or as separate asset categories	Assets depreciated individually	
Revaluation of the RAB	Yes, replacement cost methodology	
Major assets included in the RAB	Pipelines, gas receiving stations, control stations, storage facilities, metering stations, SCADA stations and systems, linepack, metering and regulation stations at the interface with the distribution network	
Inclusion and treatment of linepack	Variable amount depending on the rates of intakes and offtakes on the pipelines. Valued at a wholesale price index.	
Inclusion and treatment of working capital	No	
Timing of rolling investments into the RAB	When a capital project is commissioned. Capitalised financing costs for assets under construction according to accounting rules are also recognised.	
Depreciation		
Method	Straight-line	
Asset lives (for major asset groupings)	Pipelines	50-60 years
	Compressors	n/a
	Controllers/metering stations	20 years
	SCADA, telecoms	5-30 years
Cost of capital and financeability		
WACC method	Post-tax, nominal	
WACC value set in the two most recent regulatory periods	***Previous regulatory period***	***Current regulatory period***
	8.0% (under vanilla, nominal approach)	4.68%
WACC premium for specific investments or risks	2.13% - "risk premium applied to the natural gas sector (outside of beta coefficient), which is added to the cost of equity" (note that this applies to all investments rather than specific classes of investment)	
Primary (or only) methodology for setting the cost of equity	Capital Asset Pricing Model (CAPM)	

Latvia

<table>
<tr><td>Method for setting the risk-free rate (RFR)</td><td colspan="6">“The harmonised long-term interest rates for convergence assessment purposes is used” (percentages per annum; monthly averages; secondary market yields of government bonds with maturities of close to 10 years). 5-year average is used in calculations (until 2019 there is a transitional period where the average for the period starting from January 2014 is used).</td></tr>
<tr><td>Method for setting the equity or market risk premium (MRP/ERP)</td><td colspan="6">Take arithmetic average of MRPs used in the CEER member countries with similar risk profile.
Add MRP to RFR to estimate total market return.</td></tr>
<tr><td>Method for establishing the equity beta</td><td colspan="6">By reference to regulatory precedents elsewhere</td></tr>
<tr><td rowspan="3">WACC parameters
(RP = Regulatory Period
CoE = Cost of Equity)</td><td></td><td>RFR</td><td>MRP</td><td>Equity beta</td><td>Asset beta</td><td>CoE</td></tr>
<tr><td>Prev. RP[81]</td><td>-</td><td>-</td><td>-</td><td>-</td><td>-</td></tr>
<tr><td>Current RP</td><td>1.41%</td><td>4.90%</td><td>0.74</td><td>0.40</td><td>7.17%[82]</td></tr>
<tr><td>Method for setting the cost of debt</td><td colspan="6">Set ex ante as the 5-year average of bank interest rates on loans to corporations with an original maturity of over five years (outstanding amounts).
Until 2019 there is a transitional period where the average for the period starting from January 2014 is used.</td></tr>
<tr><td>Inclusion of debt issuance costs</td><td colspan="6">No</td></tr>
<tr><td rowspan="3">Cost of debt parameters</td><td></td><td colspan="2">Debt premium (if relevant)</td><td colspan="2">Cost of debt (net of issuance costs)</td><td>Debt issuance costs (if relevant)</td></tr>
<tr><td>Previous regulatory period</td><td colspan="2"></td><td colspan="2">-</td><td></td></tr>
<tr><td>Current regulatory period</td><td colspan="2"></td><td colspan="2">2.57%</td><td></td></tr>
<tr><td>Gearing approach</td><td colspan="6">Notional</td></tr>
<tr><td rowspan="2">Gearing level</td><td colspan="3">Previous regulatory period</td><td colspan="3">-</td></tr>
<tr><td colspan="3">Current regulatory period</td><td colspan="3">50</td></tr>
<tr><td>Financeability assessment</td><td colspan="6">No</td></tr>
<tr><td colspan="7">Other regulatory mechanisms (revenue adjustments and incentives)</td></tr>
<tr><td>Treatment of accumulated over or under-recoveries of revenues</td><td colspan="6">Adjusted between regulatory periods (but note that the regulatory period is one year).
Over-recoveries of revenue are fully accounted for in the next</td></tr>
</table>

[81] Data not provided by the NRA because the approach employed was different and therefore would not be comparable.
[82] Calculated inclusive of the 2.13% premium.

Latvia

	regulatory period (ie they reduce the allowed revenue), as are under-recoveries which increase allowed revenues in the next period (but subject to a cap for the latter equal to 10% of required revenues)
Adjustment mechanisms for differences between forecasted or allowed <u>operating expenditures</u> and realised spend	Yes - applies only to underspends alone and if these are justified as efficiency savings. In this case, a 50% sharing factor is applied.
Adjustment mechanisms for differences between forecasted or allowed <u>capital expenditures</u> and realised spend	No
Treatment of capital expenditure deferrals	None
Other revenue adjustment or incentive mechanisms	No
Regulatory reporting	
Requirement for and frequency of regulatory reporting	Annually
Coverage of regulatory reports	Regulatory financial statements, financial submissions, physical submissions
Purpose of regulatory reports	To identify how the TSO is performing relative to forecast outcomes and the reasons for differences. To allow consistent assessments over time of the TSO's cost efficiency and productivity, so informing future regulatory decisions. To allow the NRA to calculate the applicable adjustments to apply to allowed revenues in the following regulatory period because of differences between actual and forecast outcomes in the current period.
Requirement for reconciliation with audited financial statements	Yes
Key information sources	

- *NRA site: https://www.sprk.gov.lv/lapas/history32*
- *Methodology: https://likumi.lv/ta/id/287014-dabasgazes-parvades-sistemas-pakalpojuma-tarifu-aprekinasanas-metodika*

16.4.9 Portugal

Portugal

Regulatory, market and policy framework		
Regulator	Entidade Reguladora dos Serviços Energéticos (ERSE)	
TSO(s)	Redes Energéticas Nacionais (REN)	
Customer mix	Residential/commercial	47%
	Large industrial	32%
	Power generation	18%
Ratio of transit to national flows	NA – Portugal is a net importer of gas and the system is not operated for gas transit	
Network age and length	Pipeline length	1,375 km
	Original operation	1997
Regulatory governance and process		
Entity that establishes the methodology and sets allowed/target revenues	The NRA established the methodology and sets the allowed revenue target. The NRA must also consult with 'Tariff Councils', which include TSO and consumer representatives. The Tariff Councils also provide a non-binding opinion to the NRA.	
Length of revenue setting process	9 months	
Parties that can appeal NRA-determined revenues	All parties affected by the decision can appeal the decision to the Courts	
Type of appeal that is allowed	Full merit reviews are allowed.	
Overall framework for setting allowed revenues		
Type of regulation	Rate of return for capital expenditure and a mix of revenue cap and price cap for operating expenditure	
Approach to assembling the cost base	A building blocks approach is used	
Duration of regulatory period	3 years	
Determining and setting operating expenditures		
Cost categories partially or fully passed through	None	
Methods and approaches to assessing and setting opex allowances	A variety of assessments are used to determine the appropriate allowed revenues for opex including bottom-up and top-down assessments	
Inclusion of efficiency or productivity improvements	No	
Efficiency factors used in most recent regulatory period	Annual efficiency factor of 3%	
Treatment of gas shrinkage	Gas shrinkage is paid for by network users (ie losses are passed through) and there is no distinction made between types of shrinkage	
Determining and setting capital expenditures		
Methods and approaches to assessing and setting allowances	An ex-ante allowance is set based on the best forecast available to the NRA (typically based on the requirements of a National	

Portugal

	Development Plan). However, the ex-ante allowance is also assessed *ex-post* based on realised data.	
Use of uncertainty mechanisms	No	
Inclusion of efficiency or productivity improvements	No	
Efficiency factors used in most recent regulatory period	No	
Use of ex post reviews before rolling capital expenditure or assets into the RAB	Yes	
Use of tendering for large system expansions	Yes, required when expansions take place	
Regulatory asset base (RAB)		
Method used for setting the opening asset value (at the time of establishing the new regulatory framework)	The value was determined based on the privatisation of the TSO in 2007	
Depreciation of closing asset value as a single asset or as separate asset categories	Asset categories are depreciated individually	
Revaluation of the RAB	The RAB is not periodically revalued	
Major assets included in the RAB	Pipelines, compressors, and gas receiving stations	
Inclusion and treatment of linepack	No	
Inclusion and treatment of working capital	No	
Timing of rolling investments into the RAB	After a project has been commissioned, but the NRA also adjusts the allowance for the cost of debt to ensure the TSO can fund investments	
Depreciation		
Method	Straight-line depreciation	
Asset lives (for major asset groupings)	Pipelines	35 years
	Compressors	5 – 15 years
	Controllers/metering stations	-
	SCADA, telecoms	6 years
Cost of capital and financeability		
WACC method	Pre-tax nominal	
WACC value set in the two most recent regulatory periods	***Previous regulatory period***	***Current regulatory period***
	Jul-Dec 2013: 7.91% 2014: 7.44% 2015: 7.35% Jan-Jun 2016: 7.49% (subject to cap of 10.5% and floor of 7.33%)	Jul-Dec 2016: 6.05% 2017: 6.02% (subject to cap of 9.0% and floor of 5.4%)
WACC premium for specific investments or risks	No	

Portugal

<table>
<tr><td>Primary (or only) methodology for setting the cost of equity</td><td colspan="6">Capital Asset Pricing Model (CAPM)</td></tr>
<tr><td>Method for setting the risk-free rate (RFR)</td><td colspan="6">Historical yields of other country government bonds - Germany, Finland, Austria and Netherlands (countries with AAA rating when risk free rate was set, June 2016)</td></tr>
<tr><td>Method for setting the equity or market risk premium (MRP/ERP)</td><td colspan="6">The Market Risk Premium = Risk Premium for Mature Market + Country Risk spread
Risk Premium for Mature Market = Spread between S&P500 and USA 10 years treasury bond yields since 1961
Country Risk spread = Spread between Portuguese 10 years bond yields and 10 years bond yields of Germany, Finland, Austria, Netherlands and France</td></tr>
<tr><td>Method for establishing the equity beta</td><td colspan="6">By calculation
▪ Stock market index: Portuguese PSI Geral
▪ Company stocks: EDP, GALP, REN
▪ Estimation period: 3 years
▪ Frequency of observations: daily</td></tr>
<tr><td rowspan="3">WACC parameters
(RP = Regulatory Period
CoE = Cost of Equity, after-tax)</td><td></td><td>RFR</td><td>MRP</td><td>Equity beta</td><td>Asset beta</td><td>CoE (after tax)</td></tr>
<tr><td>Prev. RP</td><td>4.9%</td><td>3.75% - 4.0%</td><td>0.57</td><td>0.32</td><td>7.1%
(10.37% pre-tax)</td></tr>
<tr><td>Current RP</td><td>1.73%</td><td>5.88% - 6.88%</td><td>0.59</td><td>0.35</td><td>5.34%
(7.57% pre-tax)</td></tr>
<tr><td>Method for setting the cost of debt</td><td colspan="6">Ex ante cost setting of cost of debt. Combination of historical cost of debt and recent bond issuances with analysis of default spread for utilities with equivalent size and bond ratings</td></tr>
<tr><td>Inclusion of debt issuance costs</td><td colspan="6">No</td></tr>
<tr><td rowspan="3">Cost of debt parameters</td><td>Previous regulatory period</td><td>Debt premium (if relevant)</td><td>Cost of debt (net of issuance costs)</td><td colspan="3">Debt issuance costs (if relevant)</td></tr>
<tr><td>Previous regulatory period</td><td>1.0%</td><td>5.90%</td><td colspan="3">n/a</td></tr>
<tr><td>Current regulatory period</td><td>2.5%</td><td>4.23%</td><td colspan="3">n/a</td></tr>
<tr><td>Gearing approach</td><td colspan="6">Notional (efficient theoretical gearing, taking into account the CEER average)</td></tr>
<tr><td rowspan="2">Gearing level</td><td colspan="3">Previous regulatory period</td><td colspan="3">53%</td></tr>
<tr><td colspan="3">Current regulatory period</td><td colspan="3">50%</td></tr>
<tr><td>Financeability assessment</td><td colspan="6">No</td></tr>
</table>

Portugal

Other regulatory mechanisms (revenue adjustments and incentives)	
Treatment of accumulated over or under-recoveries of revenues	Over or under recoveries are typically adjusted within periods, but if necessary between them as well. The difference between realised costs or parameters and the revenues recovered through tariffs are accounted for in the tariffs two years later, including the estimated financial costs or gains generated by these deviations. These over or under-recoveries are carried forward using CPI. Adjustments related to demand forecast deviations and which are equal to more than 20% of allowed revenues are spread over three years
Adjustment mechanisms for differences between forecasted or allowed operating expenditures and realised spend	Yes. Adjustments to operating expenditures (OPEX) are made to correct the difference between forecasted costs and actual costs. Adjustments are made in the year following the forecast, based on estimated values and two years after the forecast, based on actual values. The year before the start of each regulatory period, the NRA defines the OPEX bases for the first year of each regulatory period. At this point a sharing of gains is made between regulated companies and consumers
Adjustment mechanisms for differences between forecasted or allowed capital expenditures and realised spend	No (note that capital expenditure is treated as cost-plus)
Treatment of capital expenditure deferrals	Not treated differently
Other revenue adjustment or incentive mechanisms	No
Regulatory reporting	
Requirement for and frequency of regulatory reporting	Yes, annual
Coverage of regulatory reports	Regulatory financial statements, financial submissions and physical submissions
Purpose of regulatory reports	To identify how the TSO is performing relative to forecast outcomes and the reasons for differences. To allow consistent assessments over time of the TSO's cost efficiency and productivity, so informing future regulatory decisions. To allow the NRA to calculate the applicable adjustments to apply to allowed revenues in the following regulatory period because of differences between actual and forecast outcomes in the current period.
Requirement for reconciliation with audited financial statements	Yes
Key information sources	

NRA: http://www.erse.pt/pt/Paginas/home.aspx

Overall:
http://www.erse.pt/pt/gasnatural/tarifaseprecos/historico/2016a2017/Documents/Par%C3%A2metros%20de%20regula%C3%A7%C3%A3o.pdf

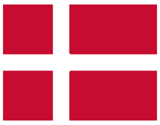
Tariff Code:
http://www.erse.pt/pt/gasnatural/regulamentos/tarifario/Documents/RT%20GN_Articulado_vs%20Portal%20Externo_capa%20e%20indice.pdf

Allowed Revenues:
http://www.erse.pt/pt/gasnatural/tarifaseprecos/20172018/Documents/Proveitos%20e%20ajustamentos.pdf

Tariffs: http://www.erse.pt/pt/gasnatural/tarifaseprecos/20172018/Documents/Tarifas%20GN%202017-2018.pdf

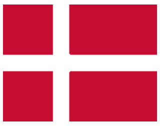
16.5 Other regimes

16.5.1 Denmark



Denmark		
Regulatory, market and policy framework		
Regulator	Forsyningstilsynet (Danish Utility Regulator (DUR))[83]	
TSO(s)	Energinet	
Customer mix	Residential/commercial	24%
	Large industrial	34%
	Power generation	42%
Ratio of transit to national flows	58%	
Network age and length	Pipeline length	860 km
	Original operation	1984
Regulatory governance and process		
DERA is an independent NRA appointed by the Ministry of Energy and Climate. It approves the revenue setting methodology proposed by Energinet, the TSO. Both the NRA and the TSO can propose full changes to the methodology but there is no structure to this process.		
Overall framework for setting allowed revenues		
The methodology is essentially a cost-plus regime based on an historical year where the allowed revenue resulting is maintained in real terms through inflation indexation. Where the resulting tariffs over- or under-recover this allowed revenue, there is scope for adjustment. The allowed revenue is updated annually using the inflation index and tariffs are reset accordingly. The regime is under review.		
Determining and setting operating expenditures		
The regime for operating expenditure is based on cost-plus analysis for the same historical year as mentioned above but for all subsequent years it can be described as a top-down approach with applicable inflation indexation. However, no efficiency factors are taken into account. Expenditures actually incurred are subject to review and it is possible to exclude expenditures not reasonably incurred. Therefore, there is *ex-post* review that can lead to adjustments. Gas shrinkage costs are a simple pass-through.		
Determining and setting capital expenditures		
Allowances for new expenditure are set using a bottom-up approach with detailed project/programme reviews, business case analysis (business cases are reviewed by the Ministry). The NRA only reviews *ex-post*. The business case is prepared by the TSO. The Ministry conducts a formal review of projects greater than 100m DKK), and the Ministry has to formally approve investments above the 100m DKK threshold. No efficiency or productivity improvements are used. *Ex post* reviews are conducted by the NRA, but with no threshold criteria. There is no tendering for large system expansions.		

[83] This was previously Energitilsynet (Danish Energy Regulatory Authority (DERA)); it changed its name on 1 July 2018.



Denmark

Regulatory asset base (RAB)

The asset base was essentially established in 2005. The NRA does not consider this a Regulatory Asset Base but it closely resembles one. The original fixed assets had a value of DKK 4,562 million. Subsequent investments were made in the construction project Ellund-Egtved. With current amortisation, the tangible fixed assets have a book value of DKK 4,579 million.

Depreciation is as a single asset.

The 'RAB' is not revalued.

Depreciation

Method	Straight-line	
Asset lives (for major asset groupings)	Pipelines	35 years
	Compressors	35 years
	Controllers/metering stations	35 years
	SCADA, telecoms	-

Cost of capital and financeability

Cost of equity and cost of debt are treated separately.

Energinet's allowed return is based on recovery of necessary costs of efficient operation plus a return on equity roughly equal to inflation (which maintains the monetary value of the assets).

Energinet participates in the Danish Government's relending system with beneficial interest rates on government loans which constitute close to 90% of reported interest-bearing debt. The government sets a yearly borrowing limit for Energinet and the company can then withdraw loans via the central bank at short notice. Energinet pays interest equal to the Danish government's borrowing rate plus a small spread of 15 basis points to the Ministry of Finance for administration.

Ex post setting of debt costs (excluding issuance costs).

Gearing is the actual *ex post* outcome.

There is no financeability assessment.

Accumulated over- or under-recoveries of revenues are fully accounted for in the next annual regulatory period through adjustment to the allowed revenue.

Regulatory reporting

Requirement for and frequency of regulatory reporting	Annually
Coverage of regulatory reports	Regulatory financial statements, financial submissions
Purpose of regulatory reports	To allow consistent assessments over time of the TSO's cost efficiency and productivity, so informing future regulatory decisions.
Requirement for reconciliation with audited financial statements	No

Key information sources

- *NRA site:* http://energitilsynet.dk/tool-menu/english/

16.5.2 Slovakia

Slovakia

Regulatory, market and policy framework		
Regulator	Úrad pre reguláciu sieťových odvetví (Regulatory Office for Network Industries)	
TSO(s)	eustream, a.s.	
Customer mix	Residential/commercial	Not provided
	Large industrial	Not provided
	Power generation	Not provided
Ratio of transit to national flows	0.07	
Network age and length	Pipeline length	2,273 km
	Original operation	1972
Overall framework for setting allowed revenues		
Tariff benchmarking is used (ie a comparison of tariffs charged on competing pipelines) for setting the maximum permitted tariffs – the NRA states that this is done by also considering information on incurred costs and other relevant documents relating to business management. This approach, however, is being reviewed in the context of harmonising Slovakian legislation with the Gas Network Tariff Code and is therefore to be changed from 2022 when new tariff and regulatory periods commence (we cannot pre-empt at this stage the methodology that is likely to be adopted for setting allowed or target revenues). Also, in Slovakia, the length of a regulatory period is the same as the tariff period. Currently, the NRA, in cooperation with the Slovak TSO, is in the process of defining the new price methodology, and the associated data collection and consultation requirements, and preparing for consultation in accordance with Articles 26, 27 and 28 of the Code.		
Cost assessment		
The NRA stated that it also analyses operating and capital expenditure data to assesses its reasonableness, and that the most relevant methods used are trend analysis for maintenance and variable OPEX. Regarding capital expenditure, detailed project reviews and Business Case and CBA methodologies are used. The NRA also submitted that costs are assessed regularly (usual on annual basis), with the last such review having been undertaken in 2017. To date, the NRA has not found reason to adjust revenues/tariffs to align with submitted cost data.		
Regulatory reporting		
Requirement for and frequency of regulatory reporting	Yes, annually	
Coverage of regulatory reports	Regulatory financial statements and financial submissions	
Purpose of regulatory reports	To allow consistent assessments over time of the TSO's cost efficiency and productivity, so informing future regulatory decisions	
Requirement for reconciliation with audited financial statements	Yes	

 **Slovakia**
Key information sources
Links to: - *Regulatory decisions:* http://www.urso.gov.sk:8088/CISRES/Agenda.nsf/0/8F331987714B1559C125805D00223EE0/$FILE/0021_2017_P%20O.pdf http://www.urso.gov.sk:8088/CISRES/Agenda.nsf/0/521F6904A06B96AAC125817F002B495E/$FILE/0100_2017_P.pdf https://tis.eustream.sk/TisWeb/#/?nav=gi.trf

17 Questionnaire for National Regulatory Authorities (NRAs) and/or Transmission System Operators (TSOs)

Contents

1.	**Regulatory, market and policy framework**			
1.1	Name of national regulatory authority (NRA) and EU Member State			
1.2	Name of regulated gas transmission system operator (TSO)			

NOTE: For countries with more than one TSO, the remaining questions of this section 1 will need to be completed separately for each TSO network. For this purpose, please use the additional tables in Annex A1 of the questionnaire. Data from other sections of the questionnaire may also differ by TSO, and we therefore request that this information be completed in the tables of Annex A2 (together with any additional information that might be needed).

1.3	What type of unbundling regime has been established? *(ITO = Independent Transmission Operator)* *(ISO = Independent System Operator)* *As per Directive 2009/73/EC*	Ownership ☐ ITO ☐ ISO ☐		
1.4	Transported gas volume (TWh)	2014	2015	2016
1.5	Peak volume transported	*Year*	*Peak volume (GWh/day)*	*Peak day (date)*
		2014		
		2015		
		2016		
1.6	Approximate ratio of peak volume transported to average daily transportation volumes			
1.7	Approximate ratio of international (transit) versus national transmission flows			
1.8	Customer mix (% of total consumption) (*approximate split over recent years*)	Residential	%	
		Commercial	%	
		Industrial	%	
		Power generation	%	
1.9	Transmission system pipeline length (km)			
1.10	When was the transmission network originally set into operation? When were	Original operation: (date/year)		

	there additional and significant expansions to the transmission system?	Major expansions: (dates/years)	
1.11	Typical (eg average over past 5 years) pipeline capacity utilisation (%)		
1.12	Other comments *(Please add any other comments you think necessary or helpful for describing your country/sector/system circumstances – if space is insufficient, please add at the end of the questionnaire)*		

2.	**Regulatory governance and process**		
2.1	Please describe the governance structure of the regulatory authority, particularly as it relates to revenue setting	Supervisory body (*eg Parliament*):	
		No. of executive and non-executive board members:	[ ] executive members [ ] non-executive members
		Powers of the board:	
		No. of staff (FTEs) employed on transmission revenue setting:	
		Use of expert panels? Please specify:	Yes ☐ No ☐
2.2	Who develops the revenue setting methodology?	NRA	☐
		TSO	☐
		Government ministry (please specify):	☐
		Other (please specify):	☐
2.3	Who approves the revenue setting methodology?	NRA	☐
		Minister (please specify):	☐
		Government	☐
		Parliament	☐
2.4	Who can initiate changes to the revenue setting methodology?	NRA	☐
		TSO	☐
		Transmission system users	☐
		Minister (please specify):	☐
		Government	☐
		Other (please specify):	☐
2.5	Is the revenue setting methodology	No	☐
		Yes, regularly (please specify):	☐

2.	Regulatory governance and process		
	periodically reviewed?	Yes, on an *ad hoc* basis	☐
2.6	Is there an approved and published revenue setting methodology?	Approved and published	☐
		Approved, but unpublished	☐
		No formally approved methodology	☐
		If published, please insert link here:	
2.7	Does the methodology exist in English?	Yes ☐	
		No ☐	
2.8	Does the revenue methodology (or the enabling legislation) establish explicit revenue setting objectives?	Yes ☐	
		No ☐	
		If yes, please specify the objectives (distinguishing between those in enabling/primary legislation and those in the methodology):	
2.9	Who approves the allowed or target TSO revenues for the regulatory period?	NRA	☐
		TSO	☐
		Government ministry (please specify):	☐
		Other (please specify):	☐
2.10	What are the steps in the revenue setting process *(eg company submission of business plan/revenue proposal – initial NRA review and clarifications/data requests – NRA consultation paper – stakeholder submissions – draft determination –*	1. 2. 3. 4. 5. 6. 7. 8. 9. 10.	

2.	Regulatory governance and process	
	consultation on draft decision - final determination – feedback on review process)	
2.11	What are the typical or formally prescribed timelines associated with the steps above (in weeks or months – please specify)?	1. 2. 3. 4. 5. 6. 7. 8. 9. 10.
2.12	Please indicate which of the documents and materials listed to the right are published?	Revenue setting model ☐ Company (redacted) business plan/revenue proposal ☐ NRA consultation papers ☐ Expert/consultant reports ☐ NRA draft decision ☐ NRA final decision ☐ NRA guidelines (eg on cost allocation, cost assessment, regulatory reporting and accounting, etc) – please specify: ☐ Other (please specify): ☐
2.13	Of the documents/ materials that are published, please indicate which are available in English?	Revenue setting model ☐ Company (redacted) business plan/revenue proposal ☐ NRA consultation papers ☐ Expert/consultant reports ☐ NRA draft decision ☐ NRA final decision ☐ NRA guidelines (eg on cost allocation, cost assessment,

2. Regulatory governance and process			
		regulatory reporting and accounting, etc.) – please specify:	☐
		Other (please specify):	☐
2.14	Can revenue determinations be appealed (whether to another NRA department, ministry, court, or other authority)?	Yes ☐ No ☐	
2.15	If yes, which is the appeal body/ies? Please describe its/their governance structure	Appeal body/ies:	
		Governance:	
2.16	If yes, who can appeal the decision? *(Multiple responses are possible)*	The TSO	☐
		Transmission system users	☐
		Others (please specify):	☐
2.17	What type of appeal is allowed?	Limited merits review (*where only certain aspects of the revenue determination can be reviewed – the appeal areas may be predefined or be limited to those areas of the decision the TSO/network user appeals*)	☐
		Full merits review (*where all aspects of the revenue determination can or must be reviewed*)	☐
		Procedural review (*where only procedural matters can be reviewed*)	☐
2.18	Is the review and decision of the appeal body time-bound (ie must the	Yes ☐ No ☐	

2.	**Regulatory governance and process**	
	review be completed, and a decision issued, within a given timeframe)?	
2.19	Are the decisions of the appeal body binding on the NRA and TSO?	Yes ☐ No ☐
2.20	Other comments *(Please add any other comments you think necessary or helpful for describing the regulatory governance framework and procedures - if space is insufficient, please add at the end of the questionnaire)*	

3.	**Overall framework for setting allowed revenues**		
3.1	What type of regulation is employed overall for controlling TSO revenues?	Price cap *(where the maximum tariff level for the TSO is set by dividing the target revenues by forecasted capacity, that is, tariffs are not adjusted for differences between forecasted and realised volumes; the average tariff may also be restricted by a price index with or without an offset for productivity improvements)*	☐
		Revenue cap *(where the revenue for the TSO is set – that is, tariffs are adjusted for differences between forecasted and realised volumes; the revenue may also be restricted by a price index with or without an offset for productivity improvements)*	☐
		Cost-plus *(where revenue is set equal to historical costs and is adjusted frequently to track cost changes)*	☐
		Rate of return *(revenues are based on historical costs and are reset at irregular intervals, as required, to maintain a reasonable allowed return)*	☐
		Hybrid (please elaborate): *(a mix of approaches eg cost-plus for capital expenditure and revenue or price cap for operating expenditure)*	☐
		Other (please specify): *(eg tariff benchmarking between TSOs)*	☐
3.2	What is the basic approach to assembling the cost base and setting the allowed or target revenues	Building block approach *(separate assessment of all cost components including of operating expenditure and capital expenditure)*	☐
		Totex approach *(capital and operating expenditures assessed in combination, that is, the two sets of expenditure are not differentiated, and the regulatory focus is on total and lifecycle costs thereby accounting for trade-offs between capital and operating and maintenance costs)*	☐
		Other (please specify):	☐

3.	Overall framework for setting allowed revenues		
3.3	Regulatory period *(ie the period for which the allowed or target revenue is set)*	Duration (number of years)	
		Current period (*year '20xx' to year '20yy'*) Previous period (*year '20xx' to year '2yyy'*)	
3.4	Are price or revenue resets permitted within a regulatory period if there are large unforeseen cost shocks or other material events or changes?	Yes ☐ No ☐ *If yes, are there formal predetermined triggers? (Please explain the circumstances permitted for revenue 'reopeners' and associated triggers):*	
3.5	Other comments *(if space is insufficient, please add at the end of the questionnaire)*	Please add any other comments you think necessary or helpful for describing the overall regulatory approach employed. *For example, if a price index and/or productivity factors are used at the general level of the price or revenue control, please specify the indices and productivity factors used for the most recent regulatory period (see immediately below)*	
		Inflation index used in the most recent regulatory period for controlling revenues or prices (eg CPI, adjusted CPI, PPI), where relevant: [*NOTE: please include only if used to set the revenue or price cap, not for converting returns or costs into real terms, which is captured elsewhere in the questionnaire*]	

3.	**Overall framework for setting allowed revenues**				
		Efficiency or productivity factor (% real) used in the most recent regulatory period at the revenue/price control level, where relevant: [*NOTE: please include only if used to set the revenue or price cap eg in the form of 'CPI-X', not for adjusting costs or setting expenditure allowances in the first place, which is captured elsewhere in the questionnaire*]			
3.6	Please state the allowed or target revenues that were set for the years shown (stating the currency and units used):	Currency (eg EUR):			
		Units (eg thousands or millions):			
		2012	2013	2014	2015	2016

4.	Determining and setting operating expenditures		
4.1	Is there a distinction made between controllable and uncontrollable operating expenditure?	Yes ☐ No ☐	
4.2	Please specify the cost <u>categories</u> that are considered (at least partly) uncontrollable by the TSO and are therefore subject to full or partial cost pass-through	Partial pass-through items	Full pass-through items
4.3	Is there a distinction made between operating expenditure incurred for (regulated) transmission and non-transmission services (as defined in the tariff network code) and unregulated activities?	Yes ☐ No ☐ *If yes, please specify the main unregulated activities undertaken by the TSO:*	
4.4	If the answer above is 'yes', how is operating expenditure for unregulated activities treated when determining allowed revenues for regulated transmission and non-transmission services?	Operating expenditure for unregulated activities is excluded altogether from allowed or target revenues - *note that this generally requires separate reporting of regulated and unregulated costs and an approved methodology for apportioning costs commonly incurred (such as corporate overheads) between the regulated and unregulated activities*	☐
		The estimated/forecasted or actual <u>revenues</u> from unregulated activities are deducted from the operating expenditure allowance	☐
4.5	Are there are other operating expenditure items (eg advertising, public relations, employee	Yes ☐ No ☐	

4.	**Determining and setting operating expenditures**		
	non-wage or in-kind compensation, etc) that are excluded for the purposes of setting allowed transmission services revenues	*If yes, please specify the excluded operating cost categories:*	
4.6	Are (controllable and allowed) operating costs mostly set *ex ante* or are they approved *ex post*?	*Ex ante* setting of allowances	☐
		Ex post review and approval of costs	☐
4.7	If allowances are predominantly set *ex ante*, how are the operating cost allowances set? *(We would expect these methods to be largely mutually exclusive, although they can also be used in combination. Where more than one method is employed, please explain how they interact with each other and/or to which cost categories they apply)*	Bottom-up assessment *(looks at the efficiency and reasonableness of individual cost items)*	☐
		Top-down assessment *(this abstracts from individual cost items and, instead, focuses on broad cost categories)*	☐
		TOTEX approach *(where operating and capital expenditures are not accounted for separately and are assessed in combination – normally used with benchmarking)*	☐
		Benchmarking *(assessments relate allowed costs to benchmarks established by reference to comparator TSOs)*	☐
		Other (please specify):	☐
4.8	If benchmarking is used, is this relied on exclusively to set cost allowances or as a sense-check on other assessment methods? *(Under the latter approach, benchmarking would, for example, be used to ensure that the cost allowances fall within a reasonable range, rather than be used to set the actual allowance)*	Benchmarking informs decisions on efficient costs	☐
		Benchmarking is relied upon to set efficient costs	☐

4.	**Determining and setting operating expenditures**		
4.9	If benchmarking is used, please specify the technique(s) employed	Corrected Ordinary Least Squares (COLS)	☐
		Stochastic Frontier Analysis (SFA)	☐
		Total Factor Productivity (TFP) index--based analysis	☐
		Data Envelopment Analysis (DEA)	☐
		Other (please specify):	☐
4.10	Are there any other assessment or analytical methods employed to assess the reasonableness and efficiency of operating expenditure? *(Multiple responses are possible)*	Trend analysis *(use of trends in historical time series data for specific cost items of the regulated TSO to detect general patterns and the relationship between associated factors or drivers)*	☐ *Please specify relevant cost categories where this is used:*
		Methodology assessment *(assessment of the robustness of the TSO models used and the related inputs, assumptions and methodologies, for developing expenditure forecasts)*	☐ *Please specify relevant cost categories where this is used:*
		Predictive modelling *(use of statistical and econometric modelling and analytical techniques to determine the expected pattern of efficient costs over the forthcoming regulatory period for specific categories of expenditure)*	☐ *Please specify relevant cost categories where this is used:*

4.	Determining and setting operating expenditures		
		Technical or engineering reviews *(usually undertaken with the assistance of specialised technical consultants)*	☐ *Please specify relevant cost categories where this is used:*
		Other (please specify):	☐ *Please specify relevant cost categories where this is used:*
4.11	Do the operating cost forecasts or allowed expenditures factor in efficiency or productivity improvements? *(These could either be embedded in the cost forecasts/allowances themselves eg where these are based on benchmarks or are set over and above the 'base' cost allowances after assessing the reasonableness of TSO cost submissions. This contrasts with applying an efficiency or productivity factor at the level of the overall price or revenue control eg in the form of 'CPI-X')?*	Yes ☐ No ☐	
4.12	If the answer to the above is 'yes', how are these efficiency factors determined?	*Method(s) for setting efficiency factors:*	
		Please specify the efficiency factors (% real) used in the most recent regulatory period:	
4.13	How are gas losses or shrinkage treated? Are there distinctions made in the treatment of distinct	*Treatment of losses or shrinkage (eg pass-through, targets, incentive mechanisms) – please specify:*	

4.	**Determining and setting operating expenditures**					
	types of shrinkage eg own use (gas consumed in compressors, and regulation and connection stations) vs unaccounted for gas?	*Categories of losses/ shrinkage – please specify:*				
4.14	What mechanisms are in place for ensuring operating expenditure does not include unreasonable or inflated margins earned by TSO-related entities?	TSO must demonstrate transactions are entered on an arm's length basis				☐
		TSO must competitively tender for services				☐
		TSO must demonstrate that the related party costs are comparable to market benchmarks				☐
		Other (please specify):				☐
4.15	Please state the allowed or target operating expenditure that was set for the years shown (stating the currency and units used) *Where there was no explicit operating expenditure allowance, please specify the outturn costs for the respective years*	Currency (eg EUR):				
		Units (eg thousands or millions):				
		2012	2013	2014	2015	2016
4.16	Other comments *(Please add any other comments you think necessary or helpful for describing the approach to setting efficient operating expenditure levels - if space is insufficient, please add at the end of the questionnaire)*					

5.	**Determining and setting capital expenditures**		
5.1	Is capital expenditure <u>generally</u> set *ex ante* or is it approved *ex post*?	*Ex ante* setting of allowances *Ex post* review and approval of costs	☐ ☐
5.2	Does the NRA (or other body or authority eg Ministry) have a role in explicitly approving specific investment programmes or projects?	Yes ☐ No ☐ *If yes, please specify for which types of investment and the approving body:*	
5.3	If allowances are <u>predominantly</u> set *ex ante*, how are capital expenditure allowances set?	Bottom-up assessment *(looks at the efficiency and reasonableness of individual capital projects or programmes)*	☐
		TOTEX approach *(where operating and capital expenditures are not accounted for separately and are assessed in combination – normally used with benchmarking)*	☐
		Benchmarking *(assessments relate allowed costs to benchmarks established by reference to comparator TSOs)*	☐
		Other (please specify):	☐
5.4	If benchmarking is used, please specify the capex categories to which this is applied *(If benchmarking is applied globally to all investment types, please tick all boxes)*	Refurbishment and replacement *(typically incurred to address the deterioration of existing assets. This includes works driven by measured or observed reductions in reliability or other quality parameters, and because of an assessment of increasing risk of system/network failure or of insufficient levels of reliability and quality)*	☐
		Network extension and reinforcement *(typically required by a need to build or augment network assets to address changes in demand for*	☐

5.	Determining and setting capital expenditures		
		transmission network services, or to maintain and/or improve the quality, reliability and security of supply in accordance with legislative and regulatory requirements, or to interconnect with neighbouring systems)	
		New connections *(works associated with customer-initiated connections, usually power plants and very large industrial users)*	☐
		Other capital expenditure *(miscellaneous expenditure with typical subcategories including IT and communications, vehicles, plant and equipment, and buildings)*	☐
5.5	If benchmarking is used, is this relied on exclusively to set cost allowances or as a sense-check on other assessment methods? *(Under the latter approach, benchmarking would, for example, be used to ensure that the cost allowances fall within a reasonable range, rather than be used to set the actual allowance*)	Benchmarking <u>informs</u> decisions on efficient costs Benchmarking is <u>purely relied upon</u> to set efficient costs	☐ ☐
5.6	If benchmarking is used, please specify the technique(s) employed	Corrected Ordinary Least Squares (COLS)	☐
		Stochastic Frontier Analysis (SFA)	☐
		Total Factor Productivity (TFP) index--based analysis	☐
		Data Envelopment Analysis (DEA)	☐
		Other (please specify):	☐

5.	Determining and setting capital expenditures		
5.7	Are there any other assessment or analytical methods employed to assess the reasonableness and efficiency of capital expenditure? *(Multiple responses are possible)*	Detailed project / programme reviews *(these normally focus on specialised technical areas, eg augmentation needs given demand forecasts and available network capacity, and often entail engineering reviews that would typically involve the assistance of subject matter experts)*	☐ *Please specify relevant cost categories where this is used:*
		Business case analysis *(like cost-benefit analysis or other similarly termed analysis such as financial justification, return on investment analysis, etc, where the fundamental requirement is that the chosen expenditure must be demonstrably superior to other options)*	☐ *Please specify relevant cost categories where this is used:*
		Examination of governance practices *(assessment of the internal processes employed by the TSO - strategic planning practices, risk management techniques, asset management policies, and procurement rules and practices - to assess needs and to underpin the business case for the specified expenditure)*	☐ *Please specify relevant cost categories where this is used:*
		Other (please specify):	☐ *Please specify relevant cost categories where this is used:*
5.8	If capital expenditure is generally set in advance, are there any other mechanisms	Logging-up *(where a TSO would be entitled, usually subject to prudency requirements, to incorporate in the next regulatory period*	☐ *Please specify relevant cost categories where this is used:*

5.	**Determining and setting capital expenditures**		
	employed for dealing with any material uncertainty regarding the timing and/or size of an individual project or programme? *(Multiple responses are possible)*	*unanticipated capital expenditure, as though it was undertaken at the beginning of the new regulatory period with the financial carrying costs of the capital expenditure included in the regulatory asset base)*	
		Budget ceiling *(where a maximum budget would be set for a specific capital expenditure programme, which is treated as a firm limit or one that would then trigger a prudency review)*	☐ *Please specify relevant cost categories where this is used:*
		Fixed unit cost *(where the unit cost of investment would usually be set with an assumed ex ante quantity applied, but with the latter updated for actual investment quantities undertaken (subject to any prudency test) when rolling forward the RAB)*	☐ *Please specify relevant cost categories where this is used:*
		Other (please specify):	☐ *Please specify relevant cost categories where this is used:*
5.9	Do the capital expenditure forecasts or allowed expenditures factor in efficiency or productivity improvements? *(These could either be embedded in the cost forecasts / allowances themselves eg where these are based on benchmarks or are set*	Yes ☐ No ☐	

5.	Determining and setting capital expenditures		
	over and above the 'base' cost allowances after assessing the reasonableness of TSO cost submissions. This contrasts with applying an efficiency or productivity factor at the level of the overall price or revenue control eg in the form of 'CPI-X')?		
5.10	If the answer to the above is 'yes', how are these efficiency factors determined?	*Method(s) for setting efficiency factors:*	
		Please specify the efficiency factors (% real) used in the most recent regulatory period:	
5.11	What mechanisms are in place for ensuring capital expenditure does not include unreasonable or inflated margins earned by TSO-related entities? *(Multiple responses are possible)*	TSO must demonstrate transactions are entered on an arm's length basis	☐
		TSO must competitively tender for services	☐
		TSO must demonstrate that the related party costs are comparable to market benchmarks	☐
		Other (please specify):	☐
5.12	After the allowed revenues have been set for the forthcoming regulatory period, is there any further periodic (eg annual) process for approving global investment plans and/or specific projects?	Yes ☐ No ☐ *If yes, please explain the process/requirements/etc:*	
5.13	Are *ex post* reviews of historical capital expenditures undertaken to assess	Yes ☐ No ☐	

<table>
<tr><th colspan="7">5. Determining and setting capital expenditures</th></tr>
<tr><td></td><td>their prudency and efficiency?</td><td colspan="5"></td></tr>
<tr><td rowspan="3">5.14</td><td rowspan="3">If the answer to the above is 'yes', are there set parameters attached to such reviews (such as materiality thresholds and scope limits)?</td><td colspan="3">Materiality thresholds:</td><td colspan="2"></td></tr>
<tr><td colspan="3">Scope of reviews (eg review of investment need, review of investment cost, review of both need and cost):</td><td colspan="2"></td></tr>
<tr><td colspan="3">Other relevant factors (eg consideration of procurement rules) or procedures attaching to such reviews (eg consultation requirements):</td><td colspan="2"></td></tr>
<tr><td rowspan="2">5.15</td><td rowspan="2">Is competitive tendering required for large transmission system expansions?</td><td colspan="5">Yes ☐
No ☐</td></tr>
<tr><td colspan="5">If yes, please state for which type of assets:</td></tr>
<tr><td rowspan="4">5.16</td><td rowspan="4">Please state the allowed or target capital expenditures that were set for the years shown (stating the currency and units used)
Where there was no explicit capital expenditure allowance, please specify the outturn costs for the respective years</td><td colspan="3">Currency (eg EUR):</td><td colspan="2"></td></tr>
<tr><td colspan="3">Units (thousands or millions):</td><td colspan="2"></td></tr>
<tr><td>2012</td><td>2013</td><td>2014</td><td>2015</td><td>2016</td></tr>
<tr><td></td><td></td><td></td><td></td><td></td></tr>
<tr><td>5.17</td><td>Other comments
(Please add any other comments you think necessary or helpful for describing the approach to setting efficient capital expenditure levels – if space is insufficient, please add at the end of the questionnaire)</td><td colspan="5"></td></tr>
</table>

<table>
<tr><th colspan="4">6. Regulatory asset base (RAB)</th></tr>
<tr><td rowspan="6">6.1</td><td rowspan="6">How was the opening asset value determined (ie at the time that the existing regulatory <u>framework or methodology</u> was established)?
(Note that this refers to the asset value established when the current revenue methodology was adopted, <u>not</u> the value determined at the beginning of the most recent regulatory period)</td><td>A value that rolled forward directly from the value <u>implicitly</u> used in previous tariff or revenue decisions or approvals (eg by a Minister or other authority prior to the establishment of the NRA as an independent decision-making entity)?</td><td>☐</td></tr>
<tr><td>A value that rolled forward directly from the value <u>explicitly</u> used in previous tariff or revenue decisions or approvals (eg by a Minister or other authority prior to the establishment of the NRA as an independent decision-making entity)?</td><td>☐</td></tr>
<tr><td>The historical cost of the assets such as the depreciated book value of the assets as per the TSO's statutory accounts at the time?</td><td>☐</td></tr>
<tr><td>A value derived from a (current cost) accounting or valuation methodology for the underlying fixed assets of the TSO?</td><td>☐
Please specify the methodology used:</td></tr>
<tr><td>A value set or implied by the privatisation of the regulated entity</td><td>☐</td></tr>
<tr><td>Other (please specify):</td><td>☐</td></tr>
<tr><td rowspan="2">6.2</td><td rowspan="2">Was the opening asset value established as an aggregate value that is depreciated at a single rate? (If not, this would mean, subject also to the answer to the next question, that investment data can be traced back to the</td><td>Yes ☐</td><td>If so, please specify the year that the opening asset value was established:</td></tr>
<tr><td>No ☐</td><td>If so, please state the earliest year that any <u>existing</u> (undepreciated) assets were constructed or purchased:</td></tr>
</table>

6.	**Regulatory asset base (RAB)**		
	original construction or purchase date for all assets)		
6.3	After assets are recognised and included in the RAB, are they depreciated as a single 'lump' (eg using an average weighted asset life) or are they depreciated individually (eg by asset category)?	The RAB is depreciated as a 'single asset' (with a weighted average asset life)	☐
		Asset categories are depreciated individually	☐
		Other (please specify):	☐
6.4	Is the RAB periodically revalued? *(Note that the reference to revaluation is to periodic adjustments to the asset base, typically employing current cost methodologies, rather than the regular updating or rolling forward of the RAB between regulatory periods for capital expenditure and depreciation)*	Yes ☐ No ☐	
6.5	If the answer above is 'yes', which methodology is typically used or was last employed for the revaluation of the RAB?	Inflation indexation *(adjustment of historical or book values using a cost index eg CPI or PPI)*	☐
		Replacement cost *(like-for-like replacement ie the current market price of purchasing or constructing the same assets)*	☐
		Modern equivalent asset (MEA) *(current market price of purchasing or constructing new assets that have the same capabilities)*	☐
		Optimised replacement cost (ORC) or	☐

6.	**Regulatory asset base (RAB)**		
		Depreciated optimised replacement cost (DORC) *(current market price of purchasing or constructing new assets that deliver the same services)*	
		Other (please specify):	☐
6.6	If the RAB is periodically revalued, how often is this undertaken? *(frequency in years, or predetermined triggers)*		
6.7	When was the last revaluation completed? *(year)*		
6.8	What impact did this have on the RAB compared to its previous closing value?	% increase (+) or decrease (-)	
		Before and after values (in nominal terms) – *please specify currency and units*	
6.9	Please indicate the major transmission asset classes or items that are included in the RAB	Pipelines	☐
		Gas receiving stations	☐
		Compressor stations	☐
		Control stations	☐
		Metering stations	☐
		SCADA stations and systems	
		Linepack (ie the amount of gas held in the transmission pipelines)	☐
		Gas storage assets	☐
		Metering and regulation (or 'gate') stations at the interface with the distribution network	☐
		Large consumer connection assets	☐
		Other (please specify):	☐
6.10	If linepack is included in the RAB, please	Amount: A fixed quantity	☐
		A depreciating asset (with a finite lifetime)	☐

<table>
<tr><th colspan="8">6. Regulatory asset base (RAB)</th></tr>
<tr><td rowspan="4"></td><td rowspan="4">describe how it is valued (stating clearly both how the amount of linepack is calculated and the price attached to it)</td><td colspan="2"></td><td colspan="2">Variable amount depending on the rates of intakes and offtakes on the pipelines</td><td colspan="2">☐</td></tr>
<tr><td colspan="2"></td><td colspan="2">Other (please specify):</td><td colspan="2">☐</td></tr>
<tr><td colspan="2">Price:</td><td colspan="2">Wholesale price index</td><td colspan="2">☐</td></tr>
<tr><td colspan="2"></td><td colspan="2">Other (please specify):</td><td colspan="2">☐</td></tr>
<tr><td rowspan="5">6.11</td><td rowspan="5">Please specify the <u>closing</u> value of the assets (in nominal terms) for the major asset groupings shown and for the most recent year for which data is available
(This should typically be the value as recorded in annual regulatory reporting statements or accounts. If these are not used, please state the projected closing value of the RAB for 2016 used for revenue setting purposes for the most recent regulatory period. Also, the closing value is after deducting depreciation for the year)</td><td colspan="4">Year:</td><td colspan="2"></td></tr>
<tr><td colspan="4">Currency (eg EUR):</td><td colspan="2"></td></tr>
<tr><td colspan="4">Unit (eg thousands or millions):</td><td colspan="2"></td></tr>
<tr><td>Pipelines</td><td>Compressors</td><td>Controllers and metering stations</td><td>SCADA, telecom</td><td colspan="2">Other (equipment, vehicles, buildings, etc)</td></tr>
<tr><td></td><td></td><td></td><td></td><td colspan="2"></td></tr>
<tr><td rowspan="4">6.12</td><td rowspan="4">Please state the <u>closing</u> value of the RAB (in nominal terms) for the last five years
(To be clear, the closing value is after</td><td colspan="4">Currency (eg EUR):</td><td colspan="2"></td></tr>
<tr><td colspan="4">Unit (eg thousands or millions):</td><td colspan="2"></td></tr>
<tr><td>2012</td><td>2013</td><td>2014</td><td>2015</td><td colspan="2">2016</td></tr>
<tr><td></td><td></td><td></td><td></td><td colspan="2"></td></tr>
</table>

6.	Regulatory asset base (RAB)		
	deducting depreciation for the year)		
6.13	Is working capital included in the RAB?	Yes ☐ No ☐	
6.14	If working capital is included, what methodology is used for its computation?	Lead-lag method *(the average time difference between when expenses must be paid and when revenue is collected, expressed in days, and multiplied by the average daily operating expenses)*	☐
		'45-day approach' *(under this convention, the TSO is allowed a cash working capital allowance equal to one-eighth (1/8 of a year ≈ 45 days) of the TSO's annual operating and maintenance expenses)*	☐
		Balance sheet method *(current assets minus current liabilities, usually excluding interest-bearing short-term deposits and liabilities)*	☐
		Other *(eg fixed percentage of revenues or net assets)* – please specify:	☐
6.15	Are customer contributions included in the RAB for the purposes of calculating depreciation?	Yes ☐ No ☐	
6.16	Are subsidies or grants included in the RAB for the purposes of calculating depreciation?	Yes ☐ No ☐	
6.17	When is realised (and approved) capital expenditure rolled into the RAB?	When incurred/at time of construction (or shortly thereafter)? When a capital project/ programme is commissioned?	☐ ☐

6.	Regulatory asset base (RAB)		
6.18	If assets are included in the RAB upon commissioning, is their value grossed up to account for financing costs?	No	☐
		Yes, using the allowed cost of capital	☐
		Yes, using the allowed cost of debt	☐
		Yes, using a prescribed rate (other than the above) – please specify:	☐
6.19	Other comments *(Please add any other comments you think necessary or helpful for describing the approach used to establish and roll forward the regulatory asset base – if space is insufficient, please add at the end of the questionnaire)*		

7.	**Depreciation**						
7.1	What method is used for determining depreciation allowances?	Straight-line (*cost spread evenly over useful life*) ☐ Declining balance (*accelerated depreciation/ higher depreciation in earlier years*) ☐ Units-of-production (*computed based on actual /estimated physical use*) ☐ Other – please specify: ☐					
7.2	Does the regulatory framework foresee and allow the possibility of re-profiling (deferring or accelerating) depreciation to meet broader objectives (*eg to provide an acceptable transition to a changed level of tariffs or to facilitate financing*)?	Yes ☐ No ☐					
7.3	Please specify the average asset lives (in years) assumed for regulatory purposes for the major asset groupings shown (*please add any other major asset categories used in the last two columns*)	Pipelines	Compre-ssors	Controll-ers, metering stations	SCADA, telecom	Other– *please specify*:	Other- *please specify*:

<table>
<tr><th colspan="8">7. Depreciation</th></tr>
<tr><td rowspan="4">7.4</td><td rowspan="4">Please specify the annual average <u>depreciation amount</u> (in nominal terms) by major asset groupings used for the most recent revenue determination / regulatory period (please add any other major asset categories used in the last two columns)</td><td colspan="4">Currency (eg EUR):</td><td colspan="2"></td></tr>
<tr><td colspan="4">Unit (eg thousands or millions):</td><td colspan="2"></td></tr>
<tr><td>Pipelines</td><td>Compre-ssors</td><td>Controll-ers, metering stations</td><td>SCADA, telecom</td><td>Other- please specify:</td><td>Other- please specify:</td></tr>
<tr><td></td><td></td><td></td><td></td><td></td><td></td></tr>
<tr><td>7.5</td><td>Other than frameworks where assets are periodically revalued, how are fully depreciated assets still in use treated for <u>regulatory</u> purposes?</td><td colspan="6">The situation is unlikely to arise because asset lives are periodically reviewed for changing information on their condition and remaining life ☐

The assets are excluded from the asset base for revenue setting purposes since their value has been recovered through past depreciation allowances ☐

Other – please specify: ☐</td></tr>
<tr><td>7.6</td><td>Other comments
(Please add any other comments you think necessary or helpful for describing the approach used to setting depreciation allowances and depreciating the RAB – if space is insufficient, please add at the end of the questionnaire)</td><td colspan="6"></td></tr>
</table>

8.	**Cost of capital and financeability**		
8.1	Is there a weighted average cost of capital (WACC) set or are equity and debt separately treated? *(Note, the former generally treats debt as an opportunity cost, while the latter considers debt costs to be more akin to operating expenditure)*	An allowed WACC is set	☐
		The cost of equity and cost of debt are treated separately	☐
8.2	Is the cost of capital set in pre-tax, 'vanilla' or post-tax terms?	Pre-tax *(a pre-tax cost of equity percentage is determined that incorporates both the rate of profit reasonably expected by shareholders (after tax) and the level of tax on that profit. Mathematically, this requires multiplying the after-tax cost of equity by the factor 1/(1 - t), the 'tax wedge')*	☐
		Vanilla *(this computation does not apply the tax wedge and therefore allows for a post-tax cost of equity, but requires that a separate allowance be made for tax on profits as a separate amount in the composition of the required revenues)*	☐
		Post-tax *(the cost of debt is multiplied by the factor (1 – t) to capture the tax benefit associated with higher gearing (as interest is deducted before tax is calculated) so no further tax deductibility is assumed when setting a separate allowance in allowed revenues for tax payments (to avoid double-counting)*	☐
8.3	If the cost of capital is set in <u>pre-tax terms</u>, please specify the tax rate (%) used for the <u>cost of equity</u> in the current and previous regulatory periods	Tax rate (%) in <u>previous</u> regulatory period	
		Tax rate (%) in <u>current</u> regulatory period	

8.	**Cost of capital and financeability**			
8.4	If the cost of capital is set in post-tax terms, please specify the tax rate (%) used for the cost of debt in the current and previous regulatory periods	Tax rate (%) in previous regulatory period		
		Tax rate (%) in current regulatory period		
8.5	Is the cost of capital set in nominal or real terms? *(Note that a nominal return includes inflation whereas a real return excludes inflation)*	Nominal cost of capital		☐
		Real cost of capital		☐
8.6	If the cost of capital is set in real terms, please specify the inflation index used to convert to real rates	Consumer Price Index (CPI)		☐
		Producer Price Index (PPI)		☐
		Other (eg CPI adjusted for some items) – please specify:		☐
8.7	If an allowed or target WACC is set, please specify the WACC established for the current and previous regulatory periods (*stating clearly the basis of the calculation ie pre/ post-tax/vanilla, nominal/real*)		WACC (%)	Calculation basis *(pre-/post-tax/vanilla, nominal/real)*
		Previous regulatory period		
		Current regulatory period		
8.8	Is a WACC premium allowed for specific investments or risks?	Yes ☐ *If so, please specify the types of investments/risks to which the premium is applied:*		
		No ☐		
8.9	If a WACC premium has been applied, please state its % value for the last two regulatory periods (and please clarify if this is differentiated	Previous regulatory period	Current regulatory period	

8.	Cost of capital and financeability		
	by type of investment/risk):		
8.10	What is the <u>primary</u> methodology used for setting the cost of equity?	Capital Asset Pricing Model (CAPM)	☐
		Dividend Growth Model (DGM)	☐
		Multi-Factor Model (please specify):	☐
		Surveys of investors and analysts	☐
		Other (please specify):	☐
8.11	Are other methodologies used as cross-checks?	Yes ☐ No ☐ *If yes, please specify the other methodologies used:*	
8.12	Where CAPM is the primary methodology used, how is the risk-free rate (RFR) established?	Historical yields of Member State government bonds (*If so, specify both the type of bond/maturities used, and the period typically used for assessing rates eg in months or years*):	☐
		Historical yields of other country government bonds (*If so, state the country and the bond maturities and measurement periods used*):	☐
		Other (please specify):	☐
8.13	Where CAPM is the primary methodology used, how is the market (or equity) risk premium (MRP/ERP) established?	Historical data reflecting actual investment returns over time (*If so, what period is typically used and which countries/markets? Also, is primary analysis undertaken or are standard references used such as the 'DMS dataset', which is prepared and updated annually by Dimson, Marsh and Staunton (DMS)*	☐

8.	Cost of capital and financeability		
		of the London Business School and discussed in the annual Global Investment Returns Sourcebook)?	
		Forward-looking data relating to investors' current expectations of returns (If so, how are these expectations assessed or measured)?	☐
		Precedents set by other regulatory authorities (If so, which authorities are typically used)?	☐
		Other (please specify):	☐
8.14	When assessing market risk premiums under CAPM, is the total equity return or the premium considered to be more stable? In other words, is a fall in the risk-free rate (RFR) treated as a fall in expectations of equity returns or as an increase in the market risk premium (MRP)?	The approach used is to estimate an underlying MRP and add that to the RFR to estimate total market returns (MRP emphasis)	☐
		The approach used is to estimate total market returns then deduct the RFR to infer an MRP (total market return emphasis)	☐
8.15	Is the MRP calculated as a geometric or arithmetic average?	Arithmetic average	☐
		Geometric average	☐
8.16	Where CAPM is the primary methodology used, how is the equity beta established?	By reference to regulatory precedents elsewhere	☐
		By calculation	☐
		If the latter (ie calculation), please specify (for the most recent regulatory period):	
		The stock market index used:	
		The regulated company stocks	

8.	**Cost of capital and financeability**					
		used:				
		The estimation period used:				
		The frequency of observations (daily, weekly, monthly)				
8.17	Please provide the target or approved cost of equity parameter values established for the current and previous regulatory periods		RFR (%)	MRP (%)	Equity (levered) beta	Asset (unlevered) beta
		Previous regulatory period				
		Current regulatory period				
8.18	Please provide the target or approved (after-tax) cost of equity established for the current and previous regulatory periods	Cost of equity (%) previous regulatory period			Cost of equity (%) current regulatory period	
8.19	Is the cost of debt set *ex ante* (without subsequent adjustment for realised debt costs) or is it set *ex post*? (*Under an ex ante approach, debt costs are separately calculated and used to set an ex ante cost of debt or WACC, with the regulated company then keeping or incurring the difference between the allowance and its actual interest costs, whereas under an ex post approach actual interest costs are passed through*)	*Ex ante* setting of cost of debt ☐ *Ex post* setting (or true-up) of debt costs ☐				
8.20	If the cost of debt is set on an *ex ante basis*, which of the	Embedded or historical interest costs ☐		By reference to the specific TSO? ☐ By reference to		

8.	Cost of capital and financeability		
	approaches shown to the right are used to estimate debt costs?		comparator businesses? If so, please specify the comparators: ☐ By reference to an index? If so, please specify the index: ☐
		Current or spot estimates (eg recent bond issuances) ☐	By reference to the specific TSO? ☐ By reference to comparator businesses? *If so, please specify the comparators*: ☐
		Combination of the above (ie weighted average of embedded and spot estimates) ☐	Please specify the weights between the two for the two most recent regulatory periods?
		Other *eg investment or central bank forecasts* (please specify): ☐	
8.21	If the cost of debt is set on an *ex ante basis*, and using comparator or market data, which of the approaches shown to the right are used?	Observed yields (ie the market cost of debt)? ☐ Risk-free rate plus <u>debt premium</u> (ie the debt cost is assumed to move in line with the risk-free rate and therefore government debt)? ☐	
8.22	If the cost of debt is set on an *ex ante basis*, and using comparator or market data, please state the bond maturities typically	Bond maturities:	
		Time span used for assessing yields or premiums:	

8.	Cost of capital and financeability					
	employed and how long a period is used for assessing yields and premiums					
8.23	Are debt issuance costs also explicitly accounted for and added to the cost of debt?	Yes ☐ No ☐				
8.24	Please provide the target or approved cost of debt <u>parameter values</u> established for the current and previous regulatory periods (if the cost of debt is set *ex ante*)	%	RFR (if relevant)	Debt premium (if relevant)	Cost of debt (net of issuance costs)	Debt issuance costs
		Previous regulatory period				
		Current regulatory period				
8.25	Please state the allowed cost of debt in the current and previous regulatory periods (if the cost of debt is set *ex post* ie as a cost pass-through)	Previous regulatory period:				
		Current regulatory period:				
8.26	Is gearing set based on the regulated TSO's actual gearing level or a notional gearing level?	Actual gearing ☐ Notional gearing ☐ *If so, please specify how the gearing level or ratio is derived:*				
8.27	Please state the gearing (defined as <u>debt divided by debt *plus* equity</u> and expressed in %) used in the two most recent regulatory decisions	Previous regulatory period gearing				
		Current regulatory period gearing				
8.28	Is a separate financeability assessment conducted to ensure the	Yes ☐ No ☐				

8. Cost of capital and financeability		
	regulated TSO can pay providers of debt and equity finance?	
8.29	If so, which credit metrics or financial ratios are used for the financeability assessment? *(Multiple responses are possible)*	Net debt/RAB ☐ Funds from operations (FFO) interest cover ratio ☐ Adjusted (for regulatory depreciation allowances) interest cover ratio or the post maintenance interest cover ratio (PMICR) ☐ FFO/Net debt ☐ Other (please specify): ☐
8.30	If a financeability assessment demonstrated the TSO were not financeable, would the NRA reconsider the allowed revenue parameters (and which)?	Yes ☐ No ☐ Parameters (if yes):
8.31	Other comments *(Please add any other comments you think necessary or helpful for describing the approach used to setting the allowed rated of return and assessing financeability – if space is insufficient, please add at the end of the questionnaire)*	

<table>
<tr><th colspan="8">9. Other regulatory mechanisms (revenue adjustments and incentives)</th></tr>
<tr><td rowspan="6">9.1</td><td rowspan="6">Please state (if relevant) the amount of accumulated over or under-recoveries of revenues (as recorded in the ‘regulatory account’)</td><td colspan="6">Over-recoveries / under-recoveries
(please delete one of the terms, if they do not apply)</td></tr>
<tr><td></td><td>2012</td><td>2013</td><td>2014</td><td>2015</td><td>2016</td></tr>
<tr><td>Amount:</td><td></td><td></td><td></td><td></td><td></td></tr>
<tr><td>Currency:</td><td colspan="5"></td></tr>
<tr><td>Unit:</td><td colspan="5"></td></tr>
<tr><td>As % of annual allowed revenue:</td><td></td><td></td><td></td><td></td><td></td></tr>
<tr><td>9.2</td><td>Are revenues and tariffs adjusted for over and under-recoveries <u>within</u> the regulatory period (eg annually, but with a lag) or <u>between</u> regulatory periods?</td><td colspan="6">Adjusted within the regulatory period ☐
Adjusted between regulatory periods ☐</td></tr>
<tr><td>9.3</td><td>Please explain how any accumulated over or under-recoveries will be treated in the forthcoming regulatory period(s) (For example, they will be fully accounted for in the next regulatory period, or they will be profiled over a specified period beyond the next regulatory term (if the latter, state the years), etc)</td><td colspan="6"></td></tr>
<tr><td>9.4</td><td>If over or under-recoveries are to be carried forward into future allowed revenues, what time value of money will be used for the adjustments?</td><td colspan="6">The allowed rate of return/WACC ☐
The allowed cost of debt ☐
A short-term borrowing rate ☐
Other (please specify): ☐</td></tr>
<tr><td>9.5</td><td>Does the regulatory framework allow for</td><td colspan="6">Yes, just for operating expenditure ☐</td></tr>
</table>

9.	Other regulatory mechanisms (revenue adjustments and incentives)		
	adjustments to be made in the subsequent years/ regulatory period for deviations between allowed and realised costs during the current regulatory period (ie are cost savings and overspends shared between the TSO and network users in some way)? *Note 1: this question relates only to controllable operating expenditure set on an ex ante basis (and not pass-through costs, for example)* *Note 2: this and subsequent questions on adjustment mechanisms would typically be relevant for incentive-based regimes (and not for cost-plus or rate of return approaches)*		
		Yes, just for capital expenditure	☐
		Yes, for both capital and operating expenditure	☐
		No	☐
9.6	If adjustments are allowed, how are these carried forward into future allowed revenues to account for the time value of money?	Using the allowed rate of return/WACC	☐
		Using the allowed cost of debt	☐
		Using a short-term borrowing rate	☐
		Other (please specify):	☐
9.7	Where adjustments are made for realised <u>operating expenditure</u>, do these apply to both underperformance (ie overspending compared to forecast or allowed costs) and outperformance (ie underspending	Adjustments apply only to outperformance (underspending)	☐
		Adjustments apply only to underperformance (overspending)	☐
		Adjustments apply to both outperformance and underperformance, symmetrically *(ie overspends and underspends are treated uniformly)*	☐
		Adjustments apply to both outperformance and underperformance, asymmetrically	☐

9.	Other regulatory mechanisms (revenue adjustments and incentives)		
	compared to forecast or allowed costs)?	*(ie overspends and underspends are differentially treated)*	
9.8	Where adjustments are made for realised operating expenditure, what regulatory mechanism is used?	A sharing mechanism *(this typically applies a sharing rate in per cent to the cumulative over/under spend during a regulatory period)* – if so, please specify the sharing rate: ___%	☐
		A rolling mechanism *(this allows the TSO to retain/incur the benefits/costs of an underspend/overspend for some time - usually equivalent to the duration of the regulatory period - after which the over/underspend is incorporated into the revenue requirement calculations)* – if so, please specify the length of time that the benefit/cost of under/over-spend is kept: ___years	☐
		Other (please specify):	☐
9.9	Where adjustments are made for realised capital expenditure, do these apply to both underperformance (ie overspending compared to forecast or allowed costs) and outperformance (ie underspending compared to forecast or allowed costs)?	Adjustments apply only to outperformance (underspending)	☐
		Adjustments apply only to underperformance (overspending)	☐
		Adjustments apply to both outperformance and underperformance, symmetrically *(ie overspends and underspends are treated uniformly)*	☐
		Adjustments apply to both outperformance and underperformance, asymmetrically *(ie overspends and underspends are differentially treated)*	☐
9.10	Where adjustments are made for realised capital expenditure, what regulatory mechanism is used?	A sharing mechanism *(this typically applies a sharing rate in per cent to the cumulative over/under spend during a regulatory period)* – if so, please specify the sharing rate: ___%	☐
		A rolling mechanism *(this allows the TSO to retain/incur the benefits/costs of an underspend/overspend for some time - usually equivalent to the duration of the regulatory period - after which the over/underspend is incorporated into the revenue requirement calculations)* – if so, please specify length of time that the benefit/cost of under/over-spend is kept: ___years	☐
		Other (please specify):	☐
9.11	Does the regulatory	Yes ☐	

9.	**Other regulatory mechanisms (revenue adjustments and incentives)**	
	framework attempt to distinguish between <u>capital expenditure deferrals</u> made for reasons of efficiency and those due to factors outside the TSO's control? *(Deferred expenditure refers to investments that were approved at the start of the regulatory period, and return and depreciation on these were incorporated in the allowed revenues, but are subsequently postponed by the TSO)*	*If so, please specify the factors that are typically considered outside the TSO's control (eg delays in obtaining planning approvals, exchange rate movements, etc):* No ☐
9.12	If the answer to the above question is 'yes', how are capital expenditure deferrals that are deemed to have arisen from factors outside the TSO's control treated?	The depreciation and allowed return on these investments is 'clawed back' (ie deducted from allowed revenues) in the next regulatory period: Fully (100%) ☐ Partially (please specify %): ☐ Other treatment (please specify): ☐
9.13	Where there is <u>no distinction of deferred capital expenditure according to cause or level of TSO control</u>, how are deferrals treated? *(Please describe the approach and include any relevant formulae for adjusting revenues)*	
9.14	Please describe any other regulatory mechanisms employed for managing uncertainty and/or distinct types of risk (eg demand	

9.	Other regulatory mechanisms (revenue adjustments and incentives)	
	risks, macroeconomic risks, etc) which are not otherwise covered in other parts of the questionnaire - if space is insufficient, please add at the end of the questionnaire	
9.15	Does the regulatory regime include payments and penalties that increase/ decrease the realised revenues (and therefore profits) of the TSOs consistent with a performance regime that sets quality and performance targets and standards	Yes ☐ No ☐
9.16	If the answer above is 'yes', please specify the performance indicators or metrics used	1. 2. 3. 4. 5. 6. 7. 8. 9. 10.

9.	Other regulatory mechanisms (revenue adjustments and incentives)	
9.17	For each of the identified indicators above (if any), please specify the targets used and state whether they are subject to 'caps' (upper limits) and/or 'collars' (lower limits), and whether they are subject to 'deadbands' *(A 'deadband' is a range of values around the target where no penalties or rewards apply. Where there are upper and lower bounds too, the incentive payments/penalties apply in the zones between the upper and lower limits and the deadband)*	1. 2. 3. 4. 5. 6. 7. 8. 9. 10.
9.18	For each of the identified indicators above (if any), please state the incentive payment that is applied to each and whether this is symmetrical (ie applies to both under and overperformance), reward-only, or penalty-only	1. 2. 3. 4. 5. 6. 7. 8. 9. 10.
9.19	Where there is a performance regime in place, is there an overall limit to the penalties and rewards (ie is there a limit to the 'revenue at risk')?	Yes ☐ *If so, please specify the limit (eg % of allowed revenue, absolute limits, etc)* No ☐

10. Regulatory reporting		
10.1	Is the TSO required to regularly submit regulatory reporting statements? *(By regulatory reporting statements, we mean reports submitted to the regulator on the TSO's* <u>*realised / outturn*</u> *costs and performance during a regulatory period and not as part of the formal periodic revenue setting process)*	Yes ☐ *If so, how often?* Annually ☐ Other (please specify): ☐ No ☐
10.2	If the answer above is yes, are the statements prepared in accordance with guidelines and/or methodologies and templates approved by the regulator?	Yes ☐ No ☐
10.3	If regulatory reporting statements are required, what do they cover? *(Multiple responses are possible)*	Regulatory financial statements *(ie pro-forma financial statements usually in the same format as the audited financial statements)* ☐ 'Financial submissions' *(ie information on actual relative to forecast costs and revenues, usually with explanations of major variances)* ☐ 'Physical submissions' *(ie information on physical outputs and indicators)* ☐ Other (please specify): ☐
10.4	Do the regulatory reporting statements need to be signed off by an auditor or other expert entity?	Yes ☐ *If so, by whom?* No ☐

10. Regulatory reporting		
10.5	Do the regulatory financial statements need to be fully reconciled with audited financial/accounting statements?	Yes ☐ No ☐
10.6	What is the purpose of the regulatory reporting statements or how are they used by the regulator? *(Multiple responses are possible)*	To identify how the TSO is performing relative to forecast outcomes and the reasons for differences ☐ To allow consistent assessments over time of the TSO's cost efficiency and productivity, so informing future regulatory decisions ☐ To allow the NRA to calculate the applicable adjustments to apply to allowed revenues in the following regulatory period because of differences between actual and forecast outcomes in the current period ☐ Other (please specify): ☐
10.7	Other comments *(Please add any other comments you think necessary or helpful for describing the approach used to regulatory reporting – if space is insufficient, please add at the end of the questionnaire)*	

Thank you for your time

Glossary of terms

45-day approach	A method for determining a working capital allowance where this is set equal to one-eighth (1/8 of a year ≈ 45 days) of the regulated firm's annual operating and maintenance expenses
Adjusted CPI	A consumer price index that excludes some of the goods or services items contained in the conventional CPI index
Adjusted interest cover ratio	An interest cover ratio adjusted for regulatory depreciation allowances, also known as the post maintenance interest cover ratio (PMICR)
Balance sheet method	A method for determining a working capital allowance where this is set equal to current assets minus current liabilities, usually excluding interest-bearing short-term deposits and liabilities
Bottom-up cost assessment	A cost assessment method that examines the efficiency and reasonableness of individual cost items
Budget ceiling	In the present context, this refers to where a maximum budget is set for a specific capital expenditure programme, which is treated as a firm limit for setting allowed revenues or one that would then trigger a prudency review
Business case analysis	A cost assessment technique that seeks to demonstrate (in a quantitatively-based manner) that the forecast expenditure is expected to be the lowest cost option in the long run relative to other feasible options in net present value terms. This is like cost-benefit analysis (or other similarly termed analysis such as financial justification, return on investment analysis, etc).
Capital Asset Pricing Model (CAPM)	One of the conventional methods for analysing how investors value future cash flows. A central part of the CAPM proposition is that the main explanatory factor for the rates of return implicit in market valuations is the asset's (perceived) sensitivity to systematic risk (also known as non-diversifiable risk or market risk). The level of systematic risk is represented by a number usually referred to as beta (β).
Closing value (of the RAB)	The end-of-year RAB balance (after adding approved capital expenditure or assets and deducting depreciation for the year)
Controllable expenditure	Expenditure that is considered to be wholly or largely within the management control of the TSO (and can therefore be subjected to incentive mechanisms).
Corrected Ordinary Least Squares (COLS)	A statistical method employed to estimate the 'efficiency frontier' of the sample firms. Ordinary least squares (OLS) refers to the general linear regression method employed in statistics, which generates a linear function of a set of explanatory variables by minimising the sum of the squares of the differences between the observed dependent variable in the given dataset and those predicted by the linear function. This is then 'corrected' or 'modified' to pass through either the least-cost comparator or through a point between the average and least-cost
Cost benchmarking	In the regulatory context, this refers to a range of statistical techniques employed to assess the cost efficiency of the regulated firm compared to other similar or comparator firms
Cost-plus	A revenue setting methodology where revenue is set equal to historical or realised costs and is adjusted frequently to track cost changes
Current cost accounting	A method of accounting in which assets are valued based on their current replacement cost or 'fair market value' rather than historical or original costs. In practice, current costs can be determined employing several different approaches
Data Envelopment Analysis (DEA)	A linear programming methodology used to identify an efficiency frontier, comprising the set of input-output combinations which cannot be improved upon, given the available data points. Firms located on the frontier are considered 100%-efficient. Other firms are given a relative efficiency score
Deadband	A range of values around a performance target where no penalties or rewards apply
Debt premium	The premium above a defined risk-free rate that debt investors require on funds lent to the regulated firm. This premium (as opposed to equity) depends on the total risk of the regulated firm (systematic and idiosyncratic) and therefore on economy-wide and firm-

	specific factors
Declining balance depreciation	Also known as accelerated depreciation. This method results in larger depreciation amounts in the earlier years of an asset's useful life and progressively lower amounts in later years. An example is where an asset is depreciated by a fixed percentage rate
Deferred expenditure	Refers to investments that were approved at the start of the regulatory period, and return and depreciation on these were incorporated in the allowed revenues, but are subsequently postponed by the TSO
Depreciated optimised replacement cost	A valuation methodology where the RAB is periodically revalued to be equal to the price of constructing or purchasing a modern equivalent asset, depreciated to reflect the shorter remaining life of the existing assets
Detailed project/ programme reviews	An analytical method employed to assess the reasonableness of capital expenditure and which normally focuses on specialised technical areas, eg augmentation needs given demand forecasts and available network capacity, and often entails engineering reviews that would typically involve the assistance of subject matter experts
Dividend Growth Model (DGM)	DGM determines the value of a firm's equity by modelling the expected future dividends receivable by the shareholders as a constantly growing perpetuity
Equity beta	Part of the capital asset pricing model to valuing equity, which measures the sensitivity of the price of an asset compared to changes in the overall market. The market's beta coefficient is 1. Any stock with a beta higher than 1 is considered more volatile than the market, and therefore riskier to hold, whereas a stock with a beta lower than 1 is expected to rise or fall more slowly than the market
Equity risk premium	Also known as the Market Risk Premium, this refers to the extra reward of equity investors (over the risk-free rate) that can be expected from a balanced portfolio of investments in an investment market
Ex post reviews of capital expenditure	A review of capital expenditure after it has been realised for the purposes of determining whether it was prudent and efficient and therefore to decide whether it ought to be remunerated (through inclusion in the RAB)
Examination of governance practices	An analytical method employed to determine the reasonableness of capital expenditure and entailing the assessment of the internal processes employed by the regulated firm - strategic planning practices, risk management techniques, asset management policies, and procurement rules and practices - to assess needs and to underpin the business case for the specified expenditure
Financial submission	A regular (usually annual) submission by the regulated firm to the regulator containing information on actual relative to forecast costs and revenues, usually with explanations of major variances
Fixed unit cost	In the present context, this refers to an approach to setting an allowance in revenues for certain capital expenditure where the unit cost of investment is set with an assumed *ex ante* quantity applied, but with the latter updated for actual investment quantities undertaken (subject to any prudency test) when rolling forward the RAB
Funds from operations (FFO) interest cover ratio	A cash-based interest cover ratio assessing a company's ability to make interest payments on its debt (common metric used by rating agencies)
Gearing	In the present context, this is a company's debt expressed as a percentage of its debt-plus- equity (note that this differs to other definitions of gearing, which characterise gearing as the debt-to-equity ratio)
Historical cost accounting	An accounting method in which assets are listed on a balance sheet with the value at which they were purchased or constructed, rather than the current market value. The historical cost principle is used to reflect the amount of capital expended to acquire an asset
Hybrid methodology	A revenue setting methodology that combines a mix of approaches (eg cost-plus for capital expenditure and revenue or price cap for operating expenditure)
Inflation indexation	In the present context, this refers to an adjustment either of overall allowed revenues or of the historical or book values of assets using an inflation index eg CPI or PPI
Lead-lag method	A method for computing a working capital allowance, which calculates the average time difference between when expenses must be paid and when revenue is collected, expressed in days, and multiplies the result by the average daily operating expenses

Levered beta	This is equivalent to the 'equity beta' and is the beta of a firm with financial leverage.
Linepack	The amount of gas occupying all pressurised sections of the transmission pipeline network. Technically, linepack is a procedure for allowing more gas to enter a pipeline than is being withdrawn, thus increasing the pressure and effectively creating storage
Logging-up	A regulatory mechanism used for capital expenditure where a TSO would be entitled, usually subject to prudency requirements, to incorporate in the next regulatory period unanticipated capital expenditure, as though it was undertaken at the beginning of the new regulatory period with the financial carrying costs of the capital expenditure included in the RAB
Market risk premium	See equity risk premium
Methodology assessment	A cost assessment analytical approach, entailing the examination of the robustness of the regulated firm's models used and the related inputs, assumptions and methodologies, for developing expenditure forecasts
Modern equivalent asset (MEA)	The current market price of purchasing or constructing new assets that have the same capabilities
MRP emphasis	In the context of the CAPM, an approach which estimates an underlying market risk premium and adds that to the risk-free rate to estimate total market returns (so that a fall in the risk-free rate, for example, reflects a fall in expectations of equity returns, and vice versa)
Multi-Factor Model	A financial model that employs multiple factors in its computations to explain equity returns. Posited by academics Fama and French who concluded that equity returns are inversely related to the size of a company (as measured by market capitalisation) and are positively related to the ratio of the book value to market value of the company's equity.
Network extension and reinforcement	Capital expenditure typically required to build or augment network assets to address changes in demand for transmission network services, or to maintain and/or improve the quality, reliability and security of supply in accordance with legislative and regulatory requirements, or to interconnect with neighbouring systems
New connections	Capital works associated with customer-initiated connections, usually power plants and very large industrial users
Nominal return	The earnings from an investment before taking into consideration inflation consequences (that is, the return includes inflation)
Opening asset value	The asset value established when the current revenue methodology was adopted (ie not the value determined at the beginning of the most recent regulatory period) and which formed the basis for remunerating debt and equity investors
Optimised replacement cost	A valuation methodology where the RAB is periodically revalued to be equal to the price of constructing or purchasing a modern equivalent asset (but without depreciating the value to reflect the shorter remaining life of the existing assets)
Outperformance	Where a regulated firm 'beats' its expenditure allowances ie its realised costs are lower than its forecast or allowed costs
Pass-through costs	Cost that are fully or partially passed through to network users and tariffs – usually applies where costs are considered to wholly or largely lie outside the control of the regulated firms (and are therefore 'ring-fenced' from any incentive arrangements)
Physical submissions	Regulatory reporting (from the TSO to the NRA) on physical outputs and indicators, usually accompanied by financial submissions where such reporting obligations are in place
Post maintenance interest cover ratio (PMICR)	See adjusted interest cover ratio
Post-tax WACC	A WACC calculation that entails multiplying the cost of debt by the factor (1 – t) to capture the tax benefit associated with higher gearing (as interest is deducted before tax is calculated) – under this approach, no further tax deductibility should be assumed when setting a separate allowance in allowed revenues for tax payments (to avoid double-counting)
Predictive modelling	Use of statistical and econometric modelling and analytical techniques to determine the expected pattern of efficient costs over the forthcoming regulatory period for specific

	categories of expenditure
Pre-tax WACC	A WACC calculation that entails the determination of a pre-tax cost of equity percentage that incorporates both the rate of profit reasonably expected by shareholders (after tax) and the level of tax on that profit. Mathematically, this requires multiplying the after-tax cost of equity by the factor 1/(1 - t), the 'tax wedge'
Price cap methodology	A revenue setting methodology where the maximum tariff level for the TSO is set by dividing the target revenues by forecasted capacity, that is, tariffs are not adjusted for differences between forecasted and realised volumes; the average tariff may also be restricted by a price index with or without an offset for productivity improvements
Rate of return methodology	A revenue setting methodology where revenues are based on historical costs and are reset at irregular intervals, as required, to maintain a reasonable allowed return
Real return	A rate of return that removes the effect of inflation ie the nominal rate of return minus an inflation factor
Refurbishment and replacement	Capital expenditure typically incurred to address the deterioration of existing assets. This includes works driven by measured or observed reductions in reliability or other quality parameters, and because of an assessment of increasing risk of system/network failure or of insufficient levels of reliability and quality
Regulatory asset base	The value of assets that are recognised as being used in the performance of regulated functions and effectively represents an expression of regulatory commitment regarding the basis of remunerating finance
Regulatory financial statements	Pro-forma financial statements usually in the same format as the audited financial statements that in some regimes must be submitted regularly (usually annually) to the regulator
Regulatory period	The period for which the allowed or target revenue is set
Regulatory reporting statements	A set of reports submitted to the regulator on the TSO's realised / outturn costs and performance during a regulatory period and not as part of the formal periodic revenue setting process – these may cover some or all the following: 'regulatory financial statements', 'financial submissions' and/or 'physical submissions'
Replacement cost	The cost of a like-for-like replacement of the existing utility assets ie the current market price of purchasing or constructing the same assets without taking depreciation into account
Revenue cap methodology	A revenue setting methodology that fixes the total revenue the TSO is permitted to earn – that is, tariffs are adjusted for differences between forecasted and realised volumes; the revenue may also be restricted by a price index with or without an offset for productivity improvements
Revenue resets or re-openers	Provisions within a revenue decision or framework for the recalculation of allowed revenues and charges if it either becomes clear that these are very different to actual costs (leading to excessive profits or losses) or that a large cost shock has occurred, the impacts of which are too large to deal with at the next regulatory review
Revenue setting methodology	A methodology that sets the allowed or target revenue for a TSO (and not the tariff design or structure used to collect the allowed revenue)
Risk-free rate (RFR)	The rate of return that would be available from a risk-free investment. Risk-free assets are usually assumed to be government bonds or bills and the RFR is the yield on that bond or bill (although in fact government bonds or bills are not entirely without risk)
Rolling mechanism	An incentive mechanism that allows the TSO to retain/incur the benefits/costs of an underspend/overspend for some time - usually equivalent to the duration of the regulatory period - after which the over/underspend is incorporated into the revenue requirement calculations
Sharing mechanism	An incentive mechanism that typically applies a sharing rate in per cent to the cumulative over/under spend during a regulatory period
Stochastic Frontier Analysis (SFA)	A statistical technique used to estimate production or cost functions, while explicitly accounting for the existence of firm inefficiency. That is, this technique allows for the fact that there can be deviations of observed choices from those considered optimal due to failures to optimise (ie inefficiency) and random shocks
Straight-line	This is where the depreciable cost of assets is reduced by an equal amount in each year

depreciation	over the assets' estimated useful life. Straight line depreciation is computed as a fixed expense by dividing the asset's depreciable cost by the number of years the asset is estimated to remain in service.
Tax wedge	The difference between before-tax and after-tax equity returns
Technical or engineering reviews	Detailed reviews of capital expenditure proposals usually undertaken with the assistance of specialised technical consultants
Top-down cost assessment	Cost assessments that abstract from individual cost items and, instead, focus on broad cost categories
Total Factor Productivity	A benchmarking technique that measures productivity as an output index divided by an input index
Total market return emphasis	In the context of the CAPM, an approach which estimates total market returns then deducts the risk-free rate to infer a market risk premium (so that a fall in the risk-free rate, for example, would reflect an increase in the risk premium and vice versa)
TOTEX approach	A cost assessment approach that assesses capital and operating expenditures in combination, that is, the two sets of expenditure are not differentiated, and the regulatory focus is on total and lifecycle costs thereby accounting for trade-offs between capital and operating and maintenance costs
Trend analysis	A cost assessment and analytical tool that uses trends in historical time series data for specific cost items of the regulated TSO to detect general patterns and the relationship between associated factors or drivers
Uncontrollable expenditure	Expenditure that is considered to be wholly or largely outside the management control of the TSO (and is therefore typically treated as pass-through)
Underperformance	Where a regulated firm overspends compared to its expenditure allowances ie its realised costs are higher than its forecast or allowed costs
Units-of-production depreciation	A depreciation method that computes the amount of depreciation in direct proportion to the amount of actual or estimated physical asset usage
Unlevered beta	Also referred to as the asset beta, the unlevered beta is the beta of a company without taking its debt into account. By removing the financial leverage (debt impact), the unlevered beta attempts to capture the risk of only the company's assets.
Vanilla WACC	A WACC computation that does not apply the tax wedge and therefore allows for a post-tax cost of equity, but requires that a separate allowance be made for tax on profits as a separate amount in the composition of the required revenues

ANNEXES

A1 Country case study 1: Incentive-based regulation of gas businesses in Australia

A1.1 Market overview

A1.1.1 Gas production and consumption

Gas is a major fuel source in Australia

Natural gas is the third highest source of primary energy consumption in Australia after oil and coal. It is used predominantly in electricity generation, mining, and manufacturing. Residential and commercial consumption make up approximately 15% of the market.

Australia is one of the world's largest gas producers

Australia has significant gas reserves. Most of Australia's gas production is exported as LNG. LNG is expected to soon become Australia's second largest commodity export (after iron ore)[84] and Australia is expected to soon overtake Qatar as the world's largest LNG exporter.

A1.1.2 Domestic gas markets

Australia has three separate domestic gas markets

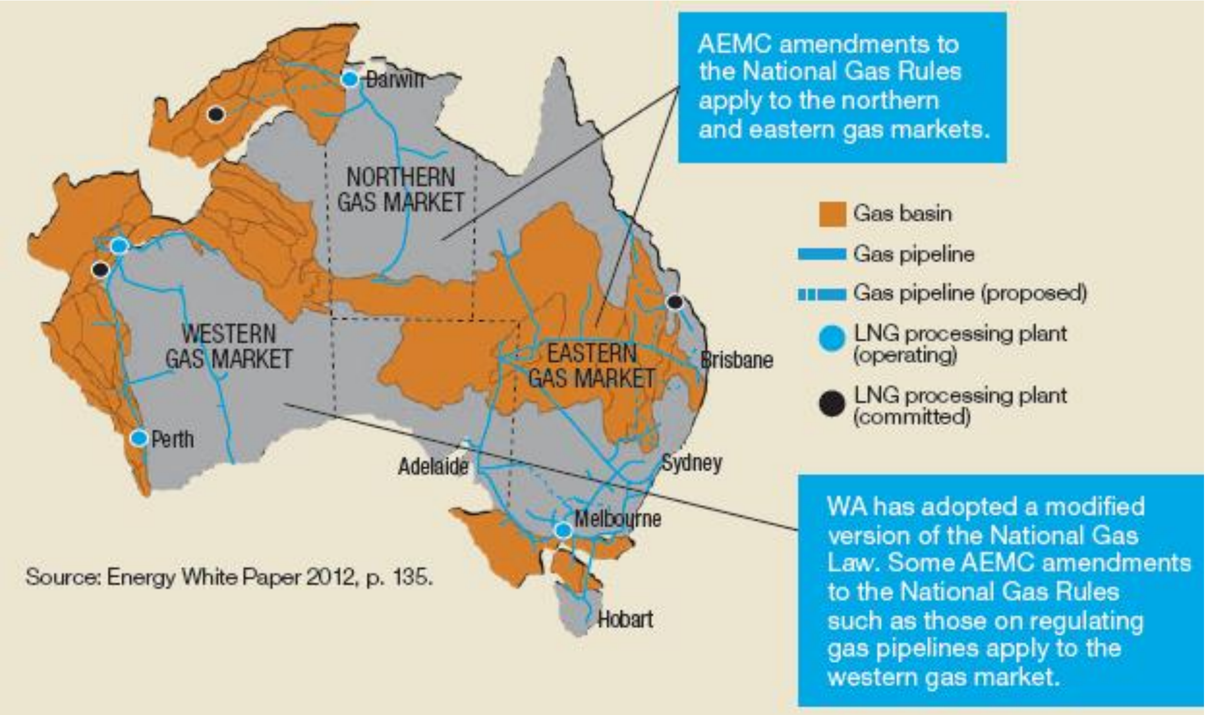
The western and eastern parts of Australia have separate natural gas and electricity markets and are not interconnected. The domestic market can be broadly categorised into three regions[85]:

- ❑ **Eastern:** An interconnected gas grid connects all of Australia's eastern and southern states and territories. The gas basins that supply this market contain around one third of Australia's gas reserves. While traditionally focused on domestic sales, this market will undergo structural change as a gas export industry further develops.
- ❑ **Western:** The gas basins of the western gas market contain over one half of Australia's gas reserves. This market is heavily focused on exports but also supplies domestic consumption in Western Australia.
- ❑ **Northern:** The northern gas market is Australia's smallest producing region. Its basins provide gas for export and for domestic consumption in the Northern Territory.

[84] Reserve Bank of Australia, Bulletin, March 2015.
[85] Source: Australian Energy Market Operator (AEMO).

These three regions are summarised in the figure below.

Figure 59 Gas regions of Australia



Source: Australian Energy Market Commission (2012)

Most gas is traded bilaterally

There is no national wholesale market for gas. Most gas is traded bilaterally via long term contracts (ie gas producers sell to large gas purchasers such as energy retailers and large industrial gas users). The Australian Energy Market Operator (AEMO) operates these markets in the eastern region, which are mainly used to trade imbalances between demand and contracted supply.

There are numerous transmission and distribution pipeline businesses

Transmission and distribution gas companies in Australia are regulated in an almost identical manner by the Australian Energy Regulator (AER), as described in later sections of this Annex. The AER's distinction between them is as follows[86]:

- **Transmission pipelines** transport natural gas from processing or storage facilities over long distances to domestic markets. The pipelines typically have wide diameters and operate under high pressure to optimise shipping capacity. There is an interconnected pipeline network covering Queensland, New South Wales, Victoria, South Australia, Tasmania and the Australian Capital Territory (ACT). Transmission pipelines in the Northern Territory are not interconnected with other jurisdictions.

[86] https://www.aer.gov.au/networks-pipelines

- A network of **distribution pipelines** delivers gas from points along transmission pipelines to industrial customers, and from gate stations to customers in cities and towns. A distribution network typically consists of high, medium and low-pressure pipelines. The high and medium pressure mains provide a 'backbone' that services areas of high demand and transports gas between population concentrations within a distribution area. The low-pressure pipes lead off the high-pressure mains to end-use customers.

The AER currently regulates 10 gas distribution companies and three gas transmission companies, as summarised in the table below.

Table 25 Australian gas transmission and distribution companies

Company	State
Distribution	
Allgas Energy	Queensland
APA Group	Australian Capital Territory, New South Wales, Victoria, Queensland, South Australia, Northern Territory, Interconnector
AusNet Services	Victoria
Australian Gas Networks Limited	New South Wales, Victoria, Queensland, South Australia, Northern Territory
Central Ranges Pipeline	New South Wales
Country Energy	New South Wales
Evoenergy	Australian Capital Territory, New South Wales
Jemena Gas Networks (NSW) Ltd	Australian Capital Territory, New South Wales
Multinet Gas	Victoria
Tas Gas Networks	Tasmania
Transmission	
Anglo Coal (Dawson) Limited	Queensland
APA GasNet Australia Pty Ltd	Victoria
APA Group	Australian Capital Territory, New South Wales, Victoria, Queensland, South Australia, Northern Territory, Interconnector

Company	State
APT Petroleum Pipelines Limited	Northern Territory
APT Pipelines (NSW) Pty Ltd	New South Wales
APT Pipelines (NT) Pty Ltd	Northern Territory
AusNet Services	Victoria
East Australian Pipeline Limited	New South Wales, South Australia
Epic Energy (Qld) Pty Ltd	Queensland
Epic Energy (SA) Pty Ltd	South Australia
NT Gas	Northern Territory
VENCorp	Victoria
WestSide Corporation Limited	Queensland

Source: AER, https://www.aer.gov.au/networks-pipelines/

A1.2 Overall regulatory framework

A1.2.1 Legislative framework

The National Gas Law and Rules define a nationwide framework for gas

The National Gas Law and Rules, first enacted in 2008, set out the regulatory framework for gas networks and pipelines in Australia. This legislation is applied by the AER in all of Australia's states, except for Western Australia. In Western Australia the regulations are applied by the Economic Regulation Authority. The National Gas Rules scope includes:

- Governing the wholesale gas balancing markets in the eastern gas market
- Providing the basis for third party access to regulated transmission and distribution network networks
- Facilitating the provision of services to retail customers.

A1.2.2 Regulatory bodies

The functions of market rule-making, market operation, and economic regulation are all separated

The key regulatory bodies in the Australian domestic gas market are as follows:[87]

- **National Competition Council (NCC)**: Makes recommendations to the Minister on whether a gas pipeline is to be regulated.
- **Australian Energy Market Commission (AEMC):** Rule-making and market development in gas markets, reviewing the energy market framework and providing advice to the Standing Council on Energy and Resources (SCER). More specifically, AMEC amends the National Gas Rules.
- **Australian Energy Market Operator (AEMO)**: The day-to-day operation and administration of the gas wholesale and retail markets in all jurisdictions except Western Australia and the Northern Territory.
- **Australian Energy Regulator (AER)**: The economic regulation of pipelines subject to regulatory arrangements under the National Gas Law, for gas transmission and distribution networks and for enforcing the National Gas Law and National Gas Rules in all jurisdictions except Western Australia.
- **Western Australian Economic Regulation Authority (WAERA)**: Regulates the western market (including gas pipelines), while the Retail Energy Market Company is responsible for retail market operation and settlement in Western Australia.

The AER's responsibilities include setting allowed revenues and dispute resolution

The key functions of the AER, which is primarily responsible for economic regulation of gas pipelines, includes:

- **Economic regulatory functions** – the AER approves access arrangements and makes determinations in relation to regulating access to electricity networks and natural gas pipelines.
- **Enforcement** – the AER monitors compliance, investigates, and may conduct proceedings in respect of breaches of legislation.
- **Dispute resolution** – the AER may hear and determine access disputes regarding access to regulated electricity networks and gas pipelines.
- **Retail authorisation and approval functions** – the AER is responsible for:
  - authorising energy retailers

[87] Sources: Australian Government: Energy White Paper 2012, Energy Consumers Australia: National Energy Regulation Handbook 2016.

  - approving standardised offers for connection services and administering other matters relating to the relationships between distributors, retailers and retail customers for both gas and electricity.

- **Retailer of Last Resort Scheme** – the AER oversees the Retailer of Last Resort scheme, which provides for circumstances where an energy retailer fails or is unable to acquire or sell energy.

A1.3 Overlap between gas and electricity regulation

Common pricing principles apply to both gas and electricity

The National Gas Law, the National Electricity Law, and the National Energy Retail Law share some content, including common statutory objectives, form of regulation, and revenue and pricing principles.

The common revenue and pricing principles include:

- **Cost recovery** - a service provider should be provided with a reasonable opportunity to recover at least their efficient costs
- **Incentives** – a service provider should be provided with effective incentives to promote economic efficiency
- **Regulatory asset base** - regard should be had to the regulatory asset base adopted in any previous determination, or in the Rules
- **Return commensurate with risks** – a price or charge for a service should allow for a return commensurate with the regulatory and commercial risks involved in providing the service
- **Levels of investment** - regard should be had to the economic costs and risks of the potential for under and over investment by a service provider
- **Levels of utilisation** - regard should be had to the economic costs and risks of the potential for under and over utilisation of the pipeline or network in question.

A1.4 Different forms of regulation

Gas pipelines can be subject to either full or light regulation

There are different forms of regulation applied by AER to gas pipelines and distribution networks:[88]

[88] Source: AER.

- *Full regulation*: Requires a pipeline owner to periodically submit an access arrangement to the AER for approval. An access arrangement sets out the terms and conditions under which third parties can use a pipeline. It must specify at least one reference service likely to be sought by a significant part of the market, and a reference tariff for that service. AER assesses the revenues needed by the pipeline business to cover its efficient costs and provide a commercial return on capital, then derives reference tariffs for the pipeline services.

- **Light regulation**: The pipeline owner determines its own tariffs. The provider must publish relevant access prices and other terms and conditions on its website. In the event of a dispute, a party seeking access to the pipeline may ask AER to arbitrate.

The form of regulation is decided by NCC at the point where it determines whether or not a pipeline should be regulated ('covered'). In making its decision, the NCC must consider:

- the likely costs that may be incurred by an efficient service provider

- the likely costs that may be incurred by efficient users / prospective users

- the likely costs of end users.

It will consider factors such as the presence of barriers to entry, any network externalities, market power possessed by the service provider, and elasticity of demand.

There are extra incentives for building new pipelines

There are also two additional mechanisms for encouraging greenfield pipeline investments:

- **15 year no-coverage (ie no-regulation) determinations**, which are available to all new pipeline projects

- **price regulation exemptions**, which are only available for new international pipelines that bring foreign gas into Australia.

A1.5 Setting allowed revenues

A1.5.1 Overall approach

The building blocks approach is used to determine allowed revenues

If a gas pipeline is determined to fall under full regulation, then AER will regulate the maximum price and revenue that can be extracted from the pipeline in question. The National Gas Rules set out the overall approach to revenue regulation, namely the 'building block' methodology. Under this methodology, total revenue is the sum of the following building blocks:

- a **return on the projected capital** base for the year

- **depreciation** of the projected capital base for the year
- the estimated cost of **corporate income tax** for the year
- increments or decrements for the year resulting from the operation of an **incentive mechanism** to encourage gains in efficiency
- a forecast of **operating expenditure** for the year.

The focus of revenue regulation is on incentivising efficiency

The key principles applied by the AER in determining the building blocks include:

- Where possible, **economic regulation is incentive-based**. Incentives are balanced to encourage network businesses to spend efficiently relative to their expenditure forecasts and service obligations. This is supported by a rigorous assessment of efficient expenditure forecasts and the testing of past performance.
- **Necessary and efficient investment is encouraged**. The method of determining the rate of return that electricity and gas network businesses can earn on their networks attempts to balance predictability with the need to consider changing market conditions.
- There is a **consumer engagement framework**. Effective consumer engagement according to AER encourages greater involvement and communication between electricity and gas network businesses and the communities they serve.

AER further explains incentive-based regulation as follows[89]:

> *a form of regulation where we forecast and lock in the total opex and capex a business will require to meet its pre-defined service and reliability targets at the start of each regulatory period. Businesses are then given financial rewards where they improve their efficiency and spend less than the forecast during the regulatory period. Put simply, if the business spends less than the forecast it will still earn revenue to cover the total forecast amount. Hence it can 'keep the difference' between the forecast and its actual expenditure until the end of the regulatory control period. Conversely, if its spending exceeds the forecast, it must carry the difference itself until the end of the period.*

The detailed approach currently applied by the AER is the result of a review undertaken in 2013, called the 'Better Regulation' programme, as detailed in the following sub-sections.[90]

[89] Source: AER, Overview of the Better Regulation Reform Package, 2014.
[90] Most of the description below is based on the AER's Overview of the Better Regulation Reform Package, 2014.

A1.5.2 Forecasting costs

Total opex and capex is approved, rather than specific projects

Opex is funded directly whereas capex is funded through the return of capital (depreciation) and the return on capital (given by the weighted average cost of capital multiplied by the RAB). The AER does not approve funding for specific projects or programmes, although businesses are required to submit detailed capex programmes as part of their revenue proposals. Instead, AER approves total annual capex and opex. Once a total forecast is set, it is for the business to decide which projects and programmes are required to meet their service and reliability requirements.

The AER uses a wide variety of benchmarking and modelling tools to forecast capex and opex

Because the AER forecasts and 'locks in' total opex and capex for each regulatory period as a way of encouraging efficiency improvements, the way opex and capex are forecast is important. The overall approach used by the AER is as follows:

- If a business is deemed efficient, its past expenditure is used as an indicator of how much it will need to spend in future.
- If the business is not responding to the AER's incentive measures, the AER sets forecasts with reference to benchmarks that reflect efficient costs.

To assess efficiency, the AER uses a variety of measures:

- **Economic benchmarking**—productivity measures used to assess a business efficiency overall
- **Category level analysis**—a key benchmarking tool, comparing how well a business delivers services for a range of individual activities and functions, including over time and with its peers
- **Predictive modelling**—statistical analysis to predict future spending needs, currently used to assess the need for upgrades or replacement as demand changes (augmentation capex, or 'augex') and expenditure needed to replace ageing assets (replacement capex, or 'repex')
- **Trend analysis**—forecasting future expenditure based on historical information, particularly useful for opex where spending is largely recurrent and predictable
- **Cost benefit analysis**—assessing whether the business has chosen spending options that reflect the best value for money
- **Project review**—a detailed engineering examination of specific proposed projects or programmes
- **Methodology review**—examining processes, assumptions, inputs and models that the business used to develop its proposal

- **Governance and policy review**—examining the business's strategic planning, risk management, asset management and prioritisation.

Capex forecasts are separated into augmentation, replacement, connection, and non-network categories

To assess businesses' capex forecasts, AER first separates capex into augmentation capex (needed to build, upgrade or replace network assets to address changes in demand), replacement capex (needed to replace ageing assets), connection capex (associated with connections and other customer driven work, and non-network capex (for example IT equipment). AER then uses a range of tools (as listed above) to review the efficiency of capex and revise estimates as required.

Opex forecasts use a base-year value, based on an assessment of efficient costs

For opex, the AER starts by determining the base-year value. In a five-year regulatory period, this is typically the third or fourth year of the previous period. AER tests whether those costs are efficient by employing some of the above assessment techniques (including economic benchmarking and category level analysis). If the analysis identifies inefficiencies in the chosen base year, AER may use a different year of actual expenditure (or an average of multiple years), or use the assessment techniques to adjust the base year.

A1.5.3 Incentive mechanisms

The AER applies capex, opex, and service standard incentive mechanisms

There are three types of incentive mechanisms built into the determination of allowed revenues for regulated businesses:

- **Capital expenditure sharing scheme (CESS)** - the CESS rewards a business if it made a capex efficiency saving and penalises it if it made a capex efficiency loss. A business retains 30 per cent of an underspend while consumers receive 70 per cent of the benefit of an underspend. A business also bears 30 per cent of the cost of an overspend, while consumers bear 70 per cent.

- **Efficiency benefit sharing scheme (EBSS)** - the EBSS allows the business to retain underspends for a total of six years, regardless of the year in which they underspend. Consumers then benefit from lower forecast opex in future regulatory periods, which leads to lower prices in the future. As with the CESS, a business retains 30 per cent of an underspend while consumers receive 70 per cent of the benefit of an underspend. A business also bears 30 per cent of the cost of an overspend, while consumers bear 70 per cent.

- **Service target performance incentive scheme (STPIS)** - this incentivises a business to maintain or improve the quality of its services through penalties and rewards related to service targets.

The CESS and EBSS incentives are balanced and constant to promote efficient spending decisions in terms of the timing, amount and type of expenditure. In theory, the expenditure incentives are also balanced with STPIS incentives, so a business does not make expenditure savings at the expense of service quality.

The AER requires businesses to carry out their own tests of whether an investment is necessary

The AER also has several mechanisms that affect allowed revenue indirectly, including the **regulatory investment test**. This is not a direct penalty/reward scheme, but rather requires a business to consider and consult on non-network alternatives when planning major network investments, which may result in expenditure being deferred or reduced.

A1.5.4 *Ex post* capex review

The AER reviews capex overspends and may not allow recovery of spending deemed inefficient

In addition to its incentive mechanisms, the AER also includes an *ex-post* review of capex, which was introduced in recent years. If a business's capex exceeds the approved forecast, the AER will examine the spending. If it determines that all or some of the overspending was inefficient, the business may not be allowed to add the excess spending to its RAB (and therefore will not pass the cost on to consumers).

A1.6 Rolling forward the regulatory asset base

A separate regulatory account is used to fund recovery of capex, with assets grouped by category

The AER uses a separate regulatory asset base (RAB) to determine the return of capital and return on capital building blocks, both of which fund capex. The RAB groups assets by category, each of which has a different regulated asset life. Depreciation is calculated on a straight-line basis using economic asset lives (which are generally very similar to technical asset lives).

The RAB is updated each year based on actual capex and forecast depreciation

The RAB is updated to reflect:

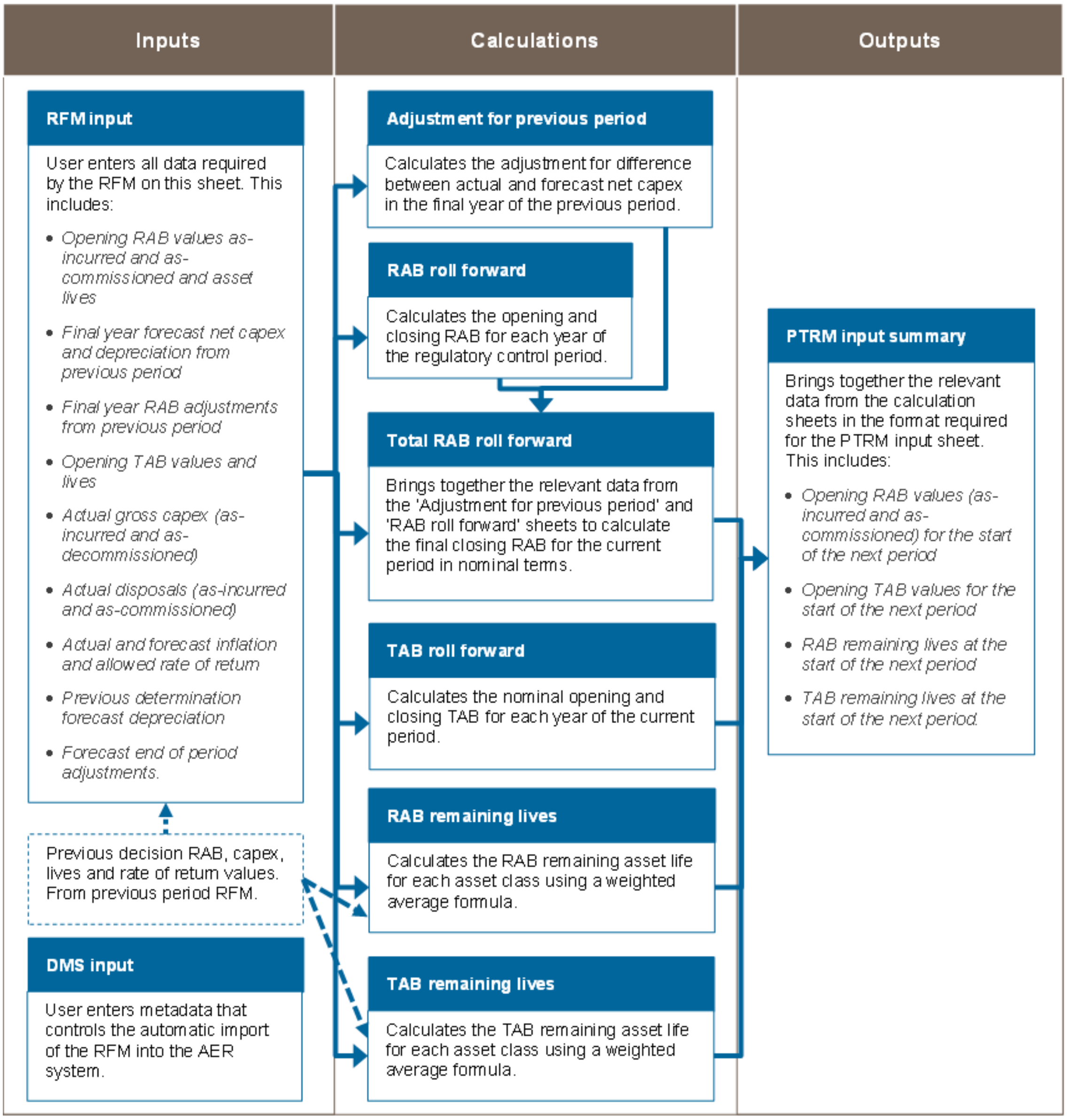
- Additions of actual capex
- Reductions for the disposal value of assets (at their sale value)
- Reductions for forecast depreciation
- Indexation for actual inflation

- Adjustment for the difference between estimated and actual capex for a previous regulatory period (due to the information not being fully available at the time of the regulatory review)
- Other adjustments for removal or addition of assets made under certain circumstances (such as a change in service classification).

The AER publishes a RAB roll forward model, for full transparency

The AER has developed a dedicated 'Roll Forward Model' that is used to determine the closing regulatory asset base (RAB) for a regulatory period. The closing RAB value for a regulatory control period as calculated by the model becomes the opening RAB to be used for the purposes of making a revenue determination for the next regulatory control period. An overview is provided in the figure below.

Figure 60 Overview of AER's RAB roll-forward model



Source: AER, Electricity transmission network service providers roll forward model handbook, October 2015

The RAB is rolled forward in nominal terms

Because it is indexed to inflation, the RAB roll forward is performed in nominal terms. To calculate allowed revenue, the AER calculates return on capital as the nominal 'vanilla' WACC multiplied by the average nominal RAB. It also subtracts the inflation indexation of the RAB from allowed revenue (from the depreciation component), to ensure that regulated businesses do not earn inflation twice.

For transmission businesses, return on capital is calculated based on capex as it is incurred, and depreciation is calculated based on capex as commissioned

The AER uses a 'partially as-incurred' approach to capex for the purposes of setting required revenues for regulated transmission businesses. Under this approach[91]:

- Return on capital is calculated recognising capex on an **as-incurred basis**
- Return of capital (regulatory depreciation) is calculated recognising capex on an as-commissioned basis.

This requires two different RABs, both of which are updated at the end of each regulatory period based on actual capex (as opposed to forecast capex):

- **A partially as-incurred RAB** — the opening RAB is rolled forward by adding as-incurred capex, subtracting straight-line depreciation based on as-commissioned capex/RAB and indexation of the opening RAB by actual inflation.
- **An as-commissioned RAB** — the opening RAB is rolled forward by adding as-commissioned capex, subtracting straight-line depreciation based on as-commissioned capex/RAB and indexation of the opening RAB by actual inflation.

Forecast rather than actual depreciation is subtracted from the RAB to align with the capex incentive mechanism

Both RABs are updated based on forecast rather than actual depreciation. This approach is used to complement the capex incentive mechanism (CESS) and ensure that regulated businesses do not receive any windfall gain/loss in terms of depreciation from actual capex being different from that forecast.

[91] Source: AER, Amendments to electricity transmission network service providers roll forward model, October 2015.

The RAB from previous regulatory periods is rolled into a single opening value for each asset category

Rather than maintain lengthy depreciation schedules, the RAB from previous regulatory periods is aggregated, for each asset category, into an opening RAB and a remaining asset life that results in the same value of depreciation over the current regulatory period.

One-off adjustments are made to account for reclassified assets

Some end of period one-off adjustments are also made to the RABs, in the form of additions to or deductions from specific asset classes at the end of a regulatory period. As an example, if assets are reclassified from regulated to unregulated services, an end of period deduction could be used to remove the value of the reclassified assets from the relevant asset class.

A1.7 Unregulated revenues

10% of unregulated revenues are deducted from regulated revenues

The AER has a mechanism, the 'shared asset mechanism' for dealing with revenues earned by a business for providing unregulated services but using the regulatory asset base. The mechanism is designed to balance administrative effort with potential consumer benefits. The shared asset mechanism functions as follows:

- The unregulated revenue that is expected to be earned from shared assets is forecasted
- The forecast is compared to the revenue requirement for regulated services
- If the forecasted unregulated revenue is expected to be greater than one per cent of the revenue requirement, AER reduces regulated revenues by 10 per cent of the value of unregulated revenues earned from shared assets.

Network businesses can propose alternative approaches to unregulated revenues, however they are unlikely to be accepted by AER if they leave consumers worse off than under the above approach.

A1.8 Return on capital

Return on capital is based on a benchmark efficient business

The AER estimates the returns on equity and debt for a hypothetical benchmark efficient business, not the actual costs of the business. This is intended to incentivise efficient financing. The core components of the AER's return on capital estimation are as follows:

- **Return on equity**: The AER's starting point is the standard (Sharpe-Lintner) Capital Asset Pricing model (CAPM) — the AER 'foundation model.' It then also uses a range of other models, methods, and information to inform the return on equity estimate. This can mean either defining a range of inputs to the CAPM model or using an entirely different model to defining a range of the overall return on equity.

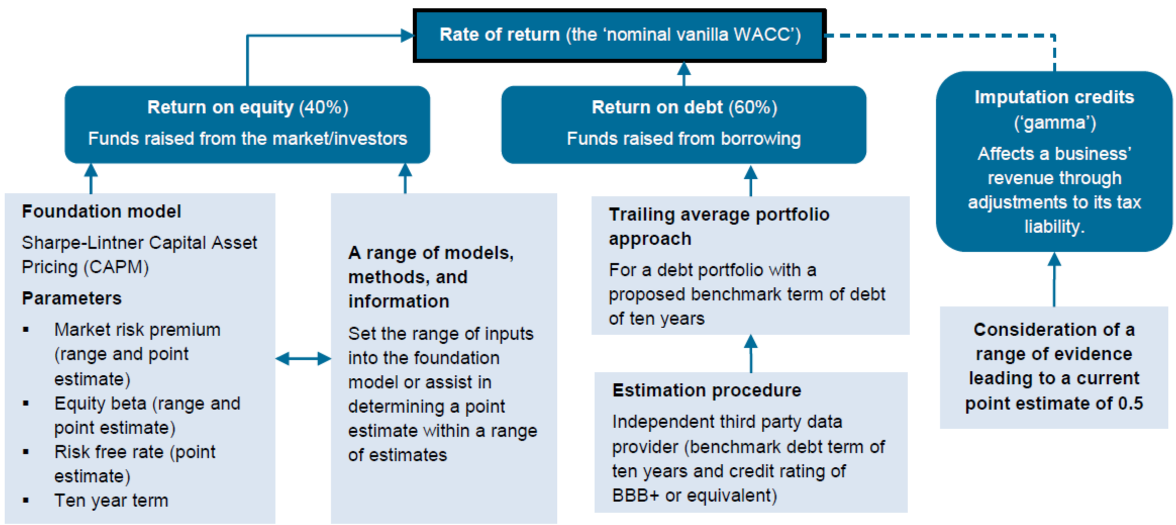
- **Return on debt**: The AER uses the average interest rate that a business would face if it raised debt annually in 10 equal parcels, ie the 'trailing average portfolio' approach. It effectively assumes that every year, one-tenth of the debt of a business is re-financed.

- **Gearing**: The AER sets a target gearing of 60%. This is based on benchmarking the actual gearing levels of businesses with a similar degree of risk to regulated Australian energy networks.

- **Imputation credits**: Under the Australian imputation tax system, investors receive imputation credits for tax paid at the company level. For eligible shareholders, imputation credits offset their Australian income tax liabilities. The AER's estimated value of imputation credits has been 0.4, from within the range 0.3 to 0.5 (note that the value of 0.5, shown in the figure below, was updated to 0.4 in 2015).

The AER's approach is further described in the figure below.

Figure 61 Rate of return estimation by AER



Source: AER, Overview of the Better Regulation Reform Package, 2014

Return on equity is based on a 10-year risk free rate, 0.7 equity beta, and an MRP benchmarked from a wide range of evidence

The AER's current approach to estimating return on equity can be further described as follows[92]:

[92] Source: AER, Rate of return issues paper, October 2017.

- **Risk free rate**. The average yield of Commonwealth Government Securities with a 10-year term to maturity, over 20 business days near the start of the energy network provider's regulatory period.

- **Equity beta**. Based on empirical estimates of the standardised correlation between the value of the market portfolio and a set of firms that approximate the risks involved in providing energy network services. These proxy firms are all Australian energy utility firms. The AER does not base its empirical range on any networks overseas. This has currently (as of 2017) produced a range of 0.4 to 0.7. The AER currently selects a point estimate of 0.7, recognising the uncertainty inherent in estimating unobservable parameters, and after consideration of beta estimates for overseas energy networks and the theory underpinning the CAPM.

- **Market risk premium**. Estimated using a wide range of evidence, including:

  - Primarily, historical realised market returns. A series of arithmetic and geometric averages of the realised market returns over varying time frames. This informs AER's estimate of a forward looking MRP.

  - Two dividend growth model (DGM) constructions. These provide directional information on the MRP point estimate in relation to the historical estimates. For example, in the current round of decisions, dividend growth model estimates were above those that realised historical returns indicated. As such, AER applied an MRP point estimate above the range that historical data indicated.

  - Several conditioning variables, including movements in dividend yields and the volatility index. This provides AER with some limited directional information.

  - Surveys and other regulators' MRP estimates as a cross-check to make sure the estimates are not out of line.

AER is currently reviewing its return on capital guidelines

The AER is currently undergoing a review of its return on capital guidelines. Key questions identified include[93]:

- To what extent has the current approach to setting the allowed rate of return achieved the National Electricity Objective (NEO) and National Gas Objective (NGO), the Allowed Rate of Return Objective (ARORO), and the related revenue and pricing principles (RPPs)?

  Should information on profitability, asset sales, financeability and any other financial information be used when assessing outcomes against the NEO and NGO, ARORO, and the related RPPs? If so, how?

[93] Source: AER, Rate of return issues paper, October 2017.

- Is the current approach to setting the benchmark term and level of gearing appropriate?
- Should the conditions and process for setting averaging periods be refined?
- To what extent are changes required to the current approach of transitioning from an on-the-day rate to a trailing average?
- Is it appropriate for AER to review the return on debt implementation approach by performing a review of the four third-party debt data series currently available to it? Please also explain if you think there is further valuing in broadening this scope of debt implementation issues and why you hold this view?
- Would a more prescriptive approach to setting the equity risk premium be appropriate? If the Guideline has a more prescriptive approach to estimating the equity risk premium, what set of conditions for reopening the Guideline would best achieve the national gas and electricity objectives and the allowed rate of return objective?
- Is the theory underlying the CAPM still appropriate for informing an equity beta point estimate? Should alternative information be used to guide the selection of an equity beta point estimate?
- What is the appropriate role of dividend growth models (DGMs) in setting the allowed return on equity?
- Is it appropriate to limit the review of the valuation of imputation credits to updating the empirical analysis? Are there any issues AER should take into account when updating empirical analysis?
- Should expected inflation and its interaction with the allowed rate of return be a priority under the Guideline review?

A1.9 Regulatory process

A1.9.1 Regulatory submissions and review

The regulatory review process has three main stages: an issues paper, draft determination, and final determination

The regulatory period for gas and electricity network businesses is typically 5 years. The process for conducting a review towards the end of each regulatory period is as follows:

- **Regulated business submits its revenue and expenditure proposal**: A regulated business submits to AER its expenditure proposal, including its proposed building blocks.

- **AER prepares an issues paper**: AER prepares an issues paper identifying key issues early in the determination process. This issues paper typically contains the AER's 'first pass' assessment indicating its preliminary view on the entity's proposal.

- **Consultation on the proposal**: AER publishes both the regulated business's proposal and its issues paper and invites public submissions. Stakeholders can also attend public forums held by the AER.

- **AER publishes its draft determination**: The draft determination sets out the AER's views on all elements of the proposal considering stakeholder views.

- **Consultation on the draft determination**: Stakeholders are again invited to make submissions on AER's draft determination and the business can revise its proposal.

- **Final determination**: After considering submissions and the revised proposal, AER publishes its final determination and analysis.

The process for gas and electricity vary slightly because the overall regulatory framework is not prescribed in the electricity law

The approach for electricity and gas varies slightly. In gas, the building block approach is prescribed in the legislation and therefore the overall regulatory framework is not reviewed by the AER. In electricity it is not prescribed in law, so AER begins the regulatory process by publishing a "framework and approach" paper two years prior to the end of each regulatory period (not included in the above steps). The framework and approach paper provides an opportunity for interested parties, including consumers, to have a say regarding which services AER should regulate and how much control AER should have over determining the prices for network services.

A typical regulator review takes between one and two years

As an illustration of timelines, the process of a recent 17-month Powerco review, an electricity transmission business, was as follows:

- Jul 2015: AER publishes Framework and Approach (applies to electricity businesses only)

- Jan 2016: Powerlink submits Regulatory Proposal

- May 2016: Submissions/ comments on Regulatory Proposal

- Sep 2016: Draft transmission determination

- Dec 2016: Powerlink submits revised Regulatory Proposal

- Apr 2017: Final transmission determination.

Regulatory reviews rely on very thorough, lengthy documents

Powerlink's original Regulatory Proposal was 153-pages long, plus 41 appendices, 7 Excel models, 19 regulatory information documents, and 45 'other' supporting documents (eg cost components).

The AER's Draft Determination document included a general overview, 2 brief 'factsheet' executive summaries, 14 supporting documents on specific details/ methodologies, 2 supporting consulting reports, and 7 Excel models.

The AER's Final Determination included an overview of Final Decision (48 pages), a methodology overview (21 pages), 2-3 page 'factsheets' on transmission determination and rate of return approach, Excel models on capital expenditure, post-tax revenue, and roll-forward calculations, and multiple consulting reports (some of which related to other ongoing AER work). It also included the following methodology appendices:

- Maximum Allowed Revenue (17 pg)
- Regulatory Asset Base (24 pg)
- Rate of Return (403 pg)
- Value of Imputation Credits (203 pg)
- Capital expenditure (50 pg)
- Negotiated services (13 pg)
- Efficiency Benefit Sharing Scheme (15 pg)
- Capital Expenditure Sharing Scheme (9 pg)
- Service Target Performance Incentive Scheme (17 pg)
- Pricing Methodology (9 pg)
- Pass-Through Events (13 pg).

A1.9.2 Stakeholder engagement

The regulatory review process includes extensive stakeholder engagement

The AER has a clear stakeholder engagement framework. Key features include:

- A **Consumer Challenge Panel** is established for each review, comprising 13 members. The expert members of the Panel provide input on consumer perspectives, including advising on whether the businesses' proposals are justified in terms of the services to be delivered to consumers and the effectiveness of network businesses' engagement activities with consumers

- Businesses are required to **describe how they have/will engage with consumers** as part of their proposal, and how they have sought to address any relevant concerns identified because of that engagement. Businesses should be able to demonstrate ongoing and genuine consumer engagement.

To use the example of the Powerlink review again, a stakeholder forum was held in March 2016, with presentations by AER, Powerlink, and the Consumer Challenge Panel (CCP). All presentations were published. AER then received submissions from a major local industry, a local university, a distribution company, and an industry body. Another public forum was held in October 2016.

A1.9.3 Disputes

The Competition Tribunal can conduct a merit review, if the issue is material

Affected parties can apply to the Australian Competition Tribunal for a review of the merits of the AER's determination. There is a threshold for an affected party to seek merits review. First, they must identify an error in one of AER's determination decisions. Second, they must establish that correcting that error will result in a decision that overall is materially preferable in terms of the long-term interests of consumers. That is, it contributes to the achievement of the national electricity objective or the national gas objective.

Decisions can be taken to court if there is an error of law in a regulatory decision

The AER's decisions are also subject to judicial review by a court. Judicial review, however, is limited to considering whether the decision contains an error of law. It does not involve an examination of the merits of the decision.

A1.9.4 Resourcing of the regulator

The AER has a full-time staff of almost 150 persons

Based on the AER's 2016 Annual Report, it comprised of 146 staff, split as follows:

- 10% retail markets
- 55% network revenue decisions
- 10% network oversight
- 7% wholesale energy markets
- 10% compliance and enforcement
- 4% corporate reporting and policy
- 4% web, IT, data reporting.

The average employee cost was AU$125,000.

The AER also has a large budget to spend on consultants

In addition to its staff costs, the AER spent AU$2.6m on consultants in 2016, 60% of which was related to legal aspects and 35% related to revenue decisions.

A2 Case study 2: Regulation of revenues in the US gas sector

A2.1 Regulatory framework

Gas pipeline regulation is a State level responsibility except when the pipeline crosses interstate lines in which case it becomes the responsibility of the Federal Energy Regulatory Commission[94] (FERC). Regardless of the applicable regulator, rate setting is guided by the Public Utility Regulatory Policies Act (PURPA), which sets rate making standards for (among other things) cost of service and interconnection. Therefore, there will be a considerable degree of uniformity in the approach to determining allowed revenue whether for electricity networks (bundled with generation or otherwise), gas pipelines or oil pipelines.

Another factor about gas pipelines is that they must operate as pure service provider and do not carry gas on behalf of the pipeline operator. Therefore, regulation of pricing is a straightforward matter in this respect.

A2.2 Administrative process

A fixed tariff rate (per customer class and service) is set in money terms whenever a new service or substantial asset is first offered. This rate continues to apply until a new Rate Case is made. There are processes for some interim adjustments to rates that do not require a new Rate Case but these seem to only apply to variables such as fuel costs or known weather variability to demand and so it is unlikely that such changes would apply to a pipeline. Therefore, there is no set periodicity to any applicable tariff.

A Rate Case will usually be initiated by a utility where they perceive a case for an increase in tariff, but the Regulator can also initiate a Rate Case where it perceives that tariffs will fall. Some States require Rate Cases at defined intervals but, with many pipelines being inter-State, FERC will be the regulator and so interval Rate Cases will not apply. This therefore requires active re-examination of information by the Regulator but there is no pre-set timeframe for information provision on which such examination would be based. Each utility can initiate a Rate Case at any time and so the framework for information provision in a multiple utility environment is inevitably complex.

A full Rate Case will typically take about a year to complete.

A2.3 Regulatory principles

The essential principle applied is 'Cost of Service'. This means that the utility must have the *opportunity to earn a reasonable rate of return of and on prudent investments, and recovery of*

[94] www.ferc.gov

reasonable expenses[95]. This, in theory will provide the incentives to efficiently develop the transmission system and to not gold-plate it although the means of assessing the efficiency are not well defined. The model is essentially:

Rate Base Investment x Rate of Return + *Operating Expenses* = *Revenue Requirement*

which will be familiar to all models, but the details will vary. Each element is covered below.

A2.4 Cost base

The Rate Base Investment (the Regulatory Asset Base) is determined by setting a single year as the 'Test Year'. Costs and investments from this year are then used for the Rate Base; the figure provides a summary of the process[96]. This year can either be a historical year or a forecast year, with the latter chosen if future investments are to be incorporated. For a forecast investment, the utility must demonstrate that the asset will be used and useful, where the test of usefulness is either in terms of improved service or lower cost than the counterfactual of the asset not being developed.

The Rate Base

	Total Plant In Service At Original Cost
-	Accumulated Provision for Depreciation
=	*Net Plant in Service*
+	Working Capital Allowances
-	Accumulated Deferred Taxes
+/-	Other Adjustments Approved by the Commission
=	*Rate Base*

For the Test Year, the RAB is assessed based on linearly depreciated assets and new allowed investments.

An asset (or share of an asset in the case of head offices, etc) is in the Rate Base to the extent that it was prudently developed at the time of investment. Therefore, there can be no stranding of investments. Equally, in most cases, there is no further incentive to efficiency of investment on a forward-looking basis. In the normal course, assets will enter the Rate Base when they become operational, but larger new assets can enter during construction. In the case of a pipeline, this may prove problematic because existing users would be required to fund an asset intended for new users.

A2.5 Cost of capital

A standard WACC-type model is applied with the exception that the gearing is determined by the utility's finance structure rather than using a reasonable benchmark. This means that a range of borrowing instruments selected by the utility and their actual cost will determine overall borrowing cost; return on equity is more benchmarked but even within this element, the utility can propose a return based on elements of its own risk profile as a company (an opportunity cost approach).

[95] Lazar, J. Electricity Regulation in the US: A Guide, Second Edition, 2016, Chapter 8, http://www.raponline.org/knowledge-center/electricity-regulation-in-the-us-a-guide-2/
[96] Ibid.

A2.6 Operating costs

These must be necessary and prudent but will usually be accepted. Some sporadic expenses will be averaged over several years. There is no inherent efficiency element to any opex allowance.

A2.7 Lessons

There are both familiar and unfamiliar elements to the US approach to regulation:

- **Revenue setting**. A cost-plus approach provides no objective test for prudent and efficient investment, but the Rate Case pursued through a hearing does ensure that these principles are adhered to. There is no other efficiency incentive in place.
- **Asset valuation**. This follows a general model of RAB-setting. It is historical cost with linear depreciation unless a future base year is chosen in which case projected depreciated historical cost plus new investment is applied.
- **Cost of capital**. Essentially a WACC approach but without pre-set gearing.
- **OPEX**. Essentially cost-plus with no efficiency element.
- **Efficiencies**. Efficient and prudent investment and operational standard but approach is *ad hoc* in determining this.
- **Deviations against forecast**. A Rate Case tariff applies until the next Rate Case is made. Managing income fluctuation is usually through a new Rate Case.

The approach is 'adversarial' in determining many of the parameters but is essentially like basic European Regulation. Where it differs is in a lack of explicit efficiency and incentive measures and in variability in approach between utilities. An additional element is that utilities predominantly self-select the timing of Rate Cases rather than working to a set timetable, which complicates any effort for multi-year tariff setting, which equally blunts incentive measures.

A3 Case study 3: New Zealand – recent introduction of price controls

New Zealand provides an example of a changing regulatory regime for gas transmission: from a 'laissez faire' approach with a threat to regulation, transmission tariffs have been closely regulated since 2011. The reason for the switch was the increasing competition from different gas sources because of depleting reserves at the largest domestic field. To create fair competition and access to the network, a firmer regulatory approach was adopted. The current regulatory regime is based on an allowed revenue approach with an incentive mechanism to reduce operating expenditures.

A3.1 Overview of network

First Gas Limited is the natural gas transmission company in New Zealand (NZ). The company owns over 2,500 km of high-pressure gas transmission pipes (including the Maui pipeline) in the North Island. First Gas Limited is a private company which operates gas transmission and distribution networks in New Zealand.

A3.2 Regulatory system

The New Zealand Commerce Commission (NZCC) regulates the provision of transmission infrastructure. The gas transmission network business in NZ was not subject to price control between 1992 and 2011 but under a laissez faire regulatory approach: tariffs were being monitored with the threat of regulatory intervention. Declining gas reserves at the Maui field and the resulting transition to a wider range of gas resources meant additional regulatory measures had to be put in place. Price and quality regulation of gas transmission and distribution was reintroduced with the Commerce Amendment Act 2008 which took effect from 2012. The purpose of regulation, as specified in the Reasons Paper, is to promote the long-term benefit of consumers in markets where there is little or no competition and little or no likelihood of a substantial increase in competition.

The NZCC uses a total allowed revenue regime. This is favoured over a weighted average price cap regime, because it provides greater incentives for innovation and investment according to NZCC. Under this framework, NZCC specifies default and customised price quality regulations known as price-quality paths.

Default price-quality paths (DPP) for all regulated suppliers are set by the Commission for a regulatory period lasting between four and five years. During the regulatory period, suppliers can apply for an alternative or 'customised' price-quality path (CPP). Both DPP and CPP are specified as an allowed revenue cap, where forecast revenue from prices must not exceed forecast allowable revenue for each pricing year of the regulatory period. Forecast allowable revenue includes forecast net allowable revenue, forecast pass-through costs, and forecast recoverable costs.

Penalties may be incurred for breaches of price-quality paths.

Under DPP, NZCC specifies an annual rate at which maximum allowed prices can increase (ie rate of change), expressed in the form of 'CPI-X', meaning prices are restricted from increasing each year by the rate of inflation less a certain number of percentage points (the X-factor). NZCC has issued a draft decision that set the X-factor to zero for the gas transmission network.

A3.3 Regulatory Asset Base

The initial asset value was calculated using depreciated historical cost determined by applying GAAP (generally accepted accounting practice in New Zealand) as of the last year of the disclosure year.

A3.4 Calculation of return on assets

The NZCC uses the WACC to estimate returns on assets. The latest WACC estimates are as follows:

- A mid-point estimate of vanilla WACC of 5.71%for the regulatory period commencing on 1 October 2017
- A mid-point estimate of post-tax WACC of 5.18% for the regulatory period commencing on 1 October 2017.

The RFR for disclosure year 2018 (2.46%) reflects the annualised bid yield to maturity on New Zealand government bonds with a five-year term to maturity. Additional parameters used in the calculation of return on assets:

- Equity beta: 0.69
- Debt premium: 1.81%. Using the Nelson- Siegel-Svensson approach, the debt premium is calculated by determining the debt premium that would reasonably be expected to apply to a vanilla NZ$ denominated bond that:
  - is issued by a gas distribution business (GPB) or EDB, (that is neither majority owned by the Crown nor a local authority)
  - is publicly traded with a credit rating of BBB+
  - has a five-year remaining term to maturity
- Gearing ratio: 42%
- Debt issuance costs: 0.2%
- Tax-adjusted MRP is 7.0% (for a 5-year period commencing on the first day of a disclosure year).

Slightly different parameters apply to Maui Developments Limited (MDL). The Maui pipeline was built exclusively for delivering gas from the Maui natural gas field in the 1970s and was acquired by First Gas Limited in 2016.

A3.5 Depreciation

Under DPP, straight line depreciation is determined by calculating 1/remaining asset life x (unallocated) opening RAB value. Alternative depreciation may be determined under CPP.

A3.6 Taxes

Average corporate tax rate set at 28.4% was calculated as a five-year average given a corporate tax rate of 30% for disclosure year 2011, and 28% for the following four disclosure years.

Average investor tax rate set at 28.1% was calculated as the five-year average given an average investor tax rate of 28.5% for disclosure year 2011, and 28% for the following four disclosure years.

A4 Summary of literature reviewed

This Annex contains a summary of key papers reviewed to inform the review of regulatory practice in setting allowed revenues for regulated infrastructure (that is, the focus is not just on gas transmission, as the principles and issues are broadly similar across infrastructures although all sectors also have their special characteristics and reasons for differentiation).

The papers span the last four decades and have been grouped around the timing of their publication (and in alphabetical order within given decades) – other groupings were explored but there was no obvious categorisation given that papers generally deal with several aspects of the regulatory setting regime. We also tried to identify papers that evaluate the various methodological approaches to inform our own evaluation framework, although most (almost all) papers that delve into this territory necessarily rely on *a priori* theoretical assessments (rather than empirical verification, for example).

We have reviewed 30 papers in total, but even this substantial number necessarily represents only a very small proportion of the available literature on the subject matter of revenue setting methodologies for monopoly infrastructure. We hope that we have captured at least some of the important papers and that this Annex can serve as a useful guide for those who wish to further explore how the thinking and practice of revenue setting has evolved in recent years. We note finally that many of the papers themselves contain extensive bibliographies for those inclined to read further.

A4.1 1980s

1. Beesley and Littlechild, 'The regulation of privatised monopolies in the United Kingdom', RAND Journal of Economics 20(3), 1989

https://www.jstor.org/stable/2555582?seq=1#page_scan_tab_contents

Type of study:	Journal article
Countries / region covered:	UK, US
Sectors covered:	Gas, electricity, telecoms, airports, water
Scope:	Compares RPI-X and rate-of-return regulation

Description of regimes for controlling revenue

- **Rate-of-return**: Firm files for change in tariff. Calculates opex, capex, and cost of capital, which the regulator audits and uses to determine a fair rate of return on capital.
- **Price cap**: For a fixed period, firm can change its prices, but the average price of a basket of its goods and services must not increase faster than RPI-X. X is set by the regulator.

Evaluation of regimes for controlling revenue

- **Cost reduction under price cap**: The firm keeps profits, incentivising cost reduction. However, this cost reduction leads to future regulator-imposed price reduction via X, potentially disincentivising cost reduction over the long term.
- **Over-capitalisation under ROR**: Incentive for over-capitalisation ('Averch-Johnson effect').
- **Allocative efficiency under price cap**: X is manually adjusted every few years. Inefficiencies if prices not in line with costs in the interim.
- **Price flexibility under price cap**: Flexible price structure within the basket and no price constraints outside the basket. Useful if there is initially a poor knowledge of prices. But cross-subsidies are allocatively inefficient and can be used anti-competitively.
- **Regulatory burden**: Price cap simple for the regulator to operate.
- **Parameters**: Price cap focuses on parameters that matter to customers.
- **Regulatory capture**: Author claims price cap less vulnerable, but Newbery (1997) and Vickers and Yarrow (1991) disagree.

Setting the efficiency/productivity factor

- In gas/electricity *transmission*, where there is monopoly and few technological shifts, an RPI-X regulator cannot tie X to technology or to other firms.
- Gas/electricity *supply*: technology is changing, so regulator 'holds the fort' until competition arrives.

Table 1: Sectors, technological change, and number of firms

	Low technical progress	High technical progress
Many regulated firms	• Water • Electricity distribution • Gas distribution • Airports	• Telecoms • Electricity generation • Electricity supply • Gas supply
One regulated firm	• Electricity transmission • Gas transmission	

2. Vickers and Yarrow, 'Privatisation: An Economic Analysis', 1988

https://econpapers.repec.org/article/eeejeborg/v_3a14_3ay_3a1990_3ai_3a1_3ap_3a156-157.htm

Type of study: Book

Countries / region covered: UK

Sectors covered: Telecommunications, Energy, Transport, Water

Scope: Analyses privatisation in UK. Theoretical perspectives on the economics of ownership, competition, and regulation. Assessment of privatisation policies in telecommunications, energy, transport, and water.

Evaluation of regimes for controlling revenue

- **Service quality under price cap**: Price cap has less incentive for service quality than ROR.

A4.2 1990s

3. Gilbert and Newbery, 'The dynamic efficiency of regulatory constitutions', RAND Journal of Economics 25(4), 1994	
https://www.jstor.org/stable/2555974?seq=1#page_scan_tab_contents	
Type of study:	Research paper
Countries / region covered:	US, UK
Sectors covered:	Various
Scope:	Models regulation as repeated game between utility with randomised demand and regulator tempted to under-reward past investment.

Evaluation of regimes for controlling revenue

- **Regulatory capture**: ROR regulation designed with commitment to an adequate rate of return can support an efficient regime as a sub-game-perfect Nash equilibrium for a larger set of parameters than ROR regulation without this commitment.

4. David M Newbery, 'Determining the regulatory asset base for utility price regulation', 1997	
Type of study:	Paper, Utilities Policy, Vol. 6, No. 1, pp. 1-8., 1997
Credentials of author:	The author is Director of the Department of Applied Economics Sidgwick Avenue, Cambridge, England
Countries / region covered:	UK
Sectors covered:	Regulated utilities; gas
Areas of focus covered:	Regulation, depreciation, price-caps, pipelines, asset valuation

RAB

- The study discusses issues relating to the determination of the Regulatory Asset Base (RAB) and the use of current cost accounting (CCA). The author finds that allowing the full depreciation of original assets to be paid to shareholders, even where this is fully deducted from the original regulatory asset base and the asset base is driven negative, overcompensates shareholders who can buy the original asset at a discount to replacement cost value. The author then proposes two solutions: marking down all depreciation of the initial assets (but of no subsequent assets) by the initial or reference MAR, and only allow this amount to be added to allowable net return in determining the cash flow attributable to shareholders. The other is to pay the full depreciation on the original assets but only while the regulatory value of these original assets is positive. The second has the advantage of paying the shareholders off first, and then compensating consumers, and is more attractive to shareholders, but it would worsen the problem of inefficient time profiles of prices for lumpy assets facing rising demand.

- The author then reviews the simple theory of accounting for interest and depreciation of an asset and specifically discusses assets created under public ownership and the efficiency aspects of pricing.

5. Newbery, 'Rate-of-return regulation versus price regulation for public utilities', 1997

http://www.econ.cam.ac.uk/people-files/emeritus/dmgn/files/palgrave.pdf

Type of study:	Research paper
Countries / region covered:	US, UK
Sectors covered:	Gas, Water, Rail, Telegraph, Electricity, Telephony
Scope:	Compares rate-of-return regulation with RPI-X regulation

Evaluation of regimes for controlling revenue

- **Cost reduction under ROR**: No incentive for efficiency improvements. During British Telecom's privatisation, the Prime Minister's adviser criticised ROR as a 100% profits tax.
- **Regulatory capture**: Price cap may only appear less vulnerable to capture than ROR due to different administrative law in the UK and US.
- **Objectivity**: ROR is based on objective actual costs. In principle, price cap is based on projected efficient costs the utility should be able to achieve. Former is more objective.
- **Price flexibility under price cap**: Pressure groups with more influence more likely to benefit. Also occurs in ROR, as evidenced by US phone rates averaged across groups with different service costs.
- **Rents**:
  - Price cap and ROR allow the firm some rent via regulatory lags. At regulatory reviews, the differences between price cap and ROR regulation disappear.
  - Price cap relies on market forces (eg banks pricing shares) to determine rate-of-return. Historically beneficial in Eastern Europe, where companies buying utilities wish to keep the required rate of return a secret, in case perceived to be excessive. But are rents always split fairly between consumers and shareholders this way?

6. Vickers and Yarrow, 'Economic Perspectives on Privatization', Journal of Economic Perspectives 5(1), 1991	
https://www.jstor.org/stable/1942688?seq=1#page_scan_tab_contents	
Type of study:	Journal article
Countries / region covered:	UK, Chile, Poland
Sectors covered:	Various
Scope:	Discusses the pros and cons of privatisation.

Evaluation of regimes for controlling revenue

- **Regulatory capture**: Under price cap, government might enforce low prices before the firm can recover costs after a sunk investment. Firms foreseeing this risk may underinvest.

7. Geoffrey Whittington, 'Current Cost Accounting: Its Role in Regulated Utilities', 1994	
http://citeseerx.ist.psu.edu/viewdoc/download?doi=10.1.1.529.5470&rep=rep1&type=pdf	
Type of study:	This paper is based on a talk given to the Utilities Finance Group of Oxford Economic Research Associates (OXERA) in February 1994
Countries / region covered:	UK
Sectors covered:	Regulated utilities, British Gas in particular
Scope:	This paper examines current cost accounting from three different perspectives (accounting standard-setting, theoretical and regulatory).

Cost of capital

- Current cost accounting (CCA) is, at best, a remote prospect as standard accounting practice in the UK due to the subjectivity of the assessment of the valuation base.
- There are problems in applying such a system to privatised utilities, including an assessment of the cost of the modern equivalent asset and the issue of stock market values being typically below the replacement cost value of assets per share. This means that the effective VTB can be regarded as being determined by the share price, rather than the cost of replacing assets.

A4.3 2000s

8. Crew and Parker, 'International Handbook on Economic Regulation, 2008

http://www.e-elgar.com/redirect.php?id=3330

Type of study:	Book
Countries / region covered:	UK
Sectors covered:	Various
Scope:	Discusses theory and practice of regulatory economics. Begins with principles, history, and methods of regulation, followed by specialist themes, including regulation of telecoms, energy, transport, and water.

Evaluation of regimes for controlling revenue

- **Service quality under price cap**: The firm increases profits by lowering service quality, as customers have no alternative competitor. The firm could cut investment or spending on operations, reducing service reliability and ability to react to events. Solutions: legally-binding targets for service levels; customer compensation schemes; financial incentives in the price-cap formula; publication of firm's performance.

9. SA Centre Economic Studies, 'Energy Network Asset Valuation: Impact on Users', 1998/ERRA, 'Determination of the RAB after Revaluation of License Holders' Assets', 2009

https://www.pc.gov.au/inquiries/completed/access/submissions/energy_users_association_of_australia_/subdr101.pdf
https://erranet.org/wp-content/uploads/2016/03/ERRA_Regulatory_Asset_Base_final_report_STC.pdf

Type of study:	Report
Countries / region covered:	N/A
Sectors covered:	Various
Scope:	(Only relevant elements of the reports are summarised below)

Asset valuation

- Three types of asset valuation methodologies that can be observed: (i) cost-based measures, (ii) economic value measures and (iii) deprival value measures.

Table 2: Valuation options

Category	Type	Description and assessment
Cost-based measures	Depreciated Actual Cost (DAC)	Determine the original purchase price of assets and subtract cumulative depreciation. This is also known as historical cost. ***Positives***: objective and data-based; experts are not necessarily required; easily audited if data are available in financial statements. ***Negatives***: data availability for older assets; divergence from current market price over time due to inflation and technological change; but inflation can be offset by revaluing assets using price index beforehand.
	Replacement Cost (RC)	Determine the cost of replacing assets with other assets (not necessarily the same) that provide same services and capacity. ***Positives***: theoretically a close representation of asset market value (as no one would pay more for the asset than replacement cost if they could instead purchase a similar asset at replacement cost). ***Negatives***: requires subjective element of estimation and judgement; not necessarily indication of what the asset would sell for on the market in practice; expert advice from engineers and accountants needed.
	Optimised Replacement Costs (ORC)	Adopt the replacement cost methodology with a focus on efficiency improvement. For example: it does not include the cost of replacing inefficient excess capacity; it could consider the possibility of reconfiguring the network; etc. ***Positives***: closer to market value than RC because the optimisation procedure mimics what would happen in a competitive market. ***Negatives***: it is often efficient to establish excess capacity that will take years to absorb, so the point of inefficiency can be subjective. Even more subjective and reliant on expert advice.
Economic-value measures	Economic Value (EV)	Determine the greater of the net present value (NPV) of future earnings of the asset and the scrap value of the asset. ***Positives***: incentivises the scrappage of inefficient assets. ***Negatives***: requires estimates of future profits; circularity issue (anticipated revenue affects NPV of future profits, which are used as the opening RAB; opening RAB affects maximum allowed revenue (MAR); MAR affects anticipated revenue).
Deprival-value measures	Deprival Value (DV)	The lesser of replacement cost (RC) and economic value (EV). ***Positives***: comparison of RC and EV of assets helps to avoid the wasteful purchase of assets that cost more than their economic value. ***Negatives***: all the issues of EV and RC.
	Optimised Deprival Value (ODV)	Lesser of optimised replacement cost (ORC) and economic value (EV). ***Positives***: ORC is a more realistic representation of cost than OC. ***Negatives***: all the issues of EV and ORC.

Depreciation

- **RAB depreciation**: Assets are assigned a regulatory asset life and a regulatory asset value. The asset value is repaid in full over the asset life. This could be repaid in equal annual instalments, known as straight-line depreciation. Alternative approaches include reducing-balance depreciation and units-of-activity depreciation, among others.
- **Alternatives to RAB depreciation**: Cash-based approach (recover the cost of principal payments separately from interest payments); net-present-value approach (recover the full cost of investments over a defined period as an annuity).

10. Frontier Economics, 'Forms of regulatory control for electricity and gas networks, 2006	
https://www.comcom.govt.nz/dmsdocument/3846	
Type of study:	Consultancy report
Countries / region covered:	New Zealand, Australia, United Kingdom, Netherlands, United States
Sectors covered:	Electricity, Gas
Scope:	Overview of theory and practice of ROR and incentive regulation in electricity and gas distribution. Argues incentive regulation has better efficiency incentives. Offers approaches to address information asymmetry. Argues there is no optimal regulatory design.

Evaluation of regimes for controlling revenue

- **Efficiency and moral hazard under ROR regulation**: Incentivises low managerial effort.
- **Over-capitalisation under ROR regulation**: Baumol and Kleverick (1970) argue that building programmes of US utilities in the '60s and '70s saw this happen in practice.
- **Metrics for comparing regulatory regimes**:
  - Efficiency incentives: in efficient scenario, price should not exceed stand-alone cost of service provision (ie costs that an efficient competitor incurs in providing that service); price should also not be less than incremental cost of service provision.
  - Volume risk: degree of volume risk borne by firm/user (inability to forecast perfectly).

Description and evaluation of regimes for controlling revenue

- **Average revenue cap:**
  - **Description:** Cap on average revenue per unit of output. Updated annually using CPI-X. If output above expected, it may earn above benchmark, and vice versa.
  - **Incentive for efficient pricing:** Firms have incentive to keep prices low to increase output and in consequence the cap. Also has incentive to expand output by pricing some services below MC, which can be achieved via excessive price discrimination.
  - **Volume risk:** Firm bears all risk as it will earn more/less revenue if output is higher/lower than expected. Correction mechanisms in practice mitigate this.
- **Total revenue cap:**
  - **Description:** Cap on allowed revenue. Updated annually using CPI-X. Adjustment mechanism: excess or shortfall in revenue considered in next period's cap.
  - **Incentive for efficient pricing:** Low incentive for prices. Improved by linking cap to customer numbers; encourages company to expand output by keeping prices low.
  - **Volume risk:** Firm bears almost no risk as its income is independent of output.
- **Hybrid revenue cap:**
  - **Description:** Combination of average and total revenue cap. Part of revenue allowance fixed; part varies with volume (but less than proportionately, unlike

average revenue cap). Latter will reflect extent to which costs perceived to vary with volumes.
    - **Incentive for efficient pricing:** The more the revenue allowance varies with volume, the greater the incentive to artificially (and inefficiently) expand output.
    - **Volume risk:** Intermediate approach where link between allowed revenue and volume is diluted, but not removed completely. Both firm and users bear some risk.
- **Tariff basket:**
    - **Description:** Cap on weighted average of prices of a basket of services. Updated using CPI-X. Common to weight based on quantity of each service sold, or revenues from each service, in a nominated base year or the previous year.
    - **Incentive for efficient pricing:** Firm could maximise revenue using price discrimination via Ramsey pricing (tariffs reflect relative demand elasticity). Less incentive than average revenue cap to price below MC; marginal revenue from an increase in volume is actual tariff the firm charges for that volume, so expanding output by charging a tariff below MC will lead the firm to incur losses on that volume.

  Volume risk:
    - Source 1: Revenue and costs increase with output: firm earn tariffs on volume sold, so earn more revenue if output is higher than expected; greater volume also has greater costs. If tariffs reflect MC, divergence between expected and actual volume will have the same effect on revenues and costs, so no risk. But most regulated firms face significant fixed costs, and services in basket may have different cost functions, so it is unlikely tariffs equal MC. Asymmetry relationship between revenues and costs exposes the firm to volume risk.
    - Source 2: Weights may be based on expected volume of services. Differences in distribution of forecast and actual service volumes may impact revenue.
- **Disaggregated price cap:**
    - **Description:** Cap on each service or customer type. Caps adjusted annually via CPI-X.
    - **Incentives for efficient pricing:** Once the regime is implemented, the firm cannot rebalance tariffs considering emerging information (eg on demand elasticities) or as costs of providing different services change, until the next regulatory review.
    - **Volume risk:** Firm bears risk for same reasons as tariff basket, but it can be mitigated. Revenue shortfall due to forecast/actual divergence can be offset in the next period.

Table 3: Comparison of incentive regulatory regimes

Regime	Incentive to price efficiently?	Pricing flexibility?	Firm bears volume risk?	Information required for setting cap, given allowed revenue?	Information required for compliance?
Average revenue cap	Some (firm can increase profits by pricing efficiently, but may engage in excessive price discrimination)	Yes	Yes	Low (volume forecast)	Low (actual revenues and volumes)

Total revenue cap	No	Yes	No	Very low	Very low (actual revenues)
Hybrid revenue cap	Some	Yes	Some	Low (volume forecast)	Low (actual revenues and volumes)
Tariff basket	Yes	Yes	Yes (to the extent that regulated tariffs do not reflect marginal costs)	Medium (volume forecast and weights for different services)	Medium (tariffs for different services)
Disaggregated price caps	Yes (but firm can only exercise this incentive to the extent that it can influence regulated tariffs)	No (except to the extent that firm can influence regulated tariffs)	Yes (to the extent that regulated tariffs do not reflect marginal costs)	High (volume forecast and costs/mechanism for setting individual tariffs)	Medium (tariffs for different services)

11. Ofgem, 'History of Energy Network Regulation', 2009

https://www.ofgem.gov.uk/ofgem-publications/51984/supporting-paper-history-energy-network-regulation-finalpdf

Type of study: Regulator's report

Countries / region covered: UK

Sectors covered: Gas, Electricity

Scope: Details the history of energy network regulation

Evaluation of regimes for controlling revenue

- **Efficiency under price cap**: Inefficiencies at onset of privatisation disappeared.
- **Cost reduction and price cap**: Incentive to reduce costs at beginning of price controls. Ofgem changed to allow firm to retain savings for whole control, regardless of when savings made.

Building blocks versus TOTEX

- **Opex bias**: Incentives for capex efficiencies lower than for opex. Solution was to assess TOTEX.

12. Ofgem, 'Longer-term price controls. Paper prepared for Ofgem's RPI-X@20 review', 2009	
https://www.ofgem.gov.uk/sites/default/files/docs/2009/12/reckon-lt-controls.pdf	
Type of study:	Report prepared by Reckon (a consultancy) for Ofgem
Countries / region covered:	UK
Sectors covered:	Gas, Electricity
Scope:	A report that identifies potential options, benefits and drawbacks relating to the use of longer-term price controls

Length of regulatory periods

- **Long-term vision**: Longer price controls give network companies a clear financial stake in controlling their costs over a longer time horizon. 5 years was found to be too short.
- **WACC**: Investors in energy network may feel longer price controls bring less regulatory risk, contributing to a lower cost of capital.
- **Longer price controls pose risk to allocative efficiency**: If reviewed less frequently, the firm's prices may diverge further from MC, creating inefficient consumption patterns.
- **Consumer waiting time for cost reductions**: Longer regulatory periods mean a longer lag before lower costs can be reflected in lower prices. This can be addressed in a few ways:
  - Price controls that use forecast productivity improvements.
  - Opex and capex can be subject to risk-sharing around an upfront expenditure forecast. For every £1 the firm saves, share this between investors (in terms of higher profits) and consumers (through lower prices).

13. Ofgem, 'Regulating energy networks for the future: RPI-X@20, Delivering outcomes: Ensuring the future regulatory framework is adaptable', 2009	
https://www.ofgem.gov.uk/sites/default/files/docs/2009/10/final-adaptability-paper_0.pdf	
Type of study:	Regulator's report
Countries / region covered:	UK
Sectors covered:	Gas, Electricity
Scope:	This paper discusses adaptability and the treatment of uncertainty in the context of the RPI-X regimes applied to energy networks.

Revenue adjustment mechanisms (including forward-looking mechanisms)

Table 4: Tools to manage uncertainty in price controls

Tool	Description	Electricity transmission	Gas transmission	Electricity distribution	Gas distribution
Length of control period	The shorter the period, the greater the protection. Can weaken efficiency incentives.	5 years	5 years	5 years	5 years
Sharing factor	The price control only exposes the companies to a share of any under- or over-spends.	25% of any capex over/under spend, subject to efficiency test, capex safety net mechanism.	25% of any capex over/under spend, subject to efficiency test.	Fixed percentage (29-40%) of any capex over/under spend.	Fixed percentage (33-36%) of any capex over/under spend, subject to efficiency.
Price protection (indexation)	With RPI indexation, allowances are typically indexed by RPI. With input price indexation, allowed revenues are a function of a defined input price index.	RPI term in RPI-X.	RPI term in RPI-X.	RPI term in RPI-X.	RPI term in RPI-X, shrinkage mechanism where revenue varies with a shrinkage gas price index.
Revenue driver	Allowed revenues are a function of a pre-defined variable. May be a global adjustment or a unit cost driver applied to a specific area of expenditure.	Linked to amount of generation connected and boundary flows.	Revenue allowed to increase in response to the delivery of user commitment via auctions.	Customer numbers, units distributed.	Unit cost driver applied to the mains replacement programme (Repex).
Use it or lose it	Allowed revenue *ex-ante* for a set purpose. Clawed back if not required.	Innovation Funding Incentive, equity-raising costs.	Innovation Funding Incentive, equity-raising costs.	Innovation Funding Incentive	Innovation Funding Incentive
Specific re-openers	These allow price limits to be changed before the next price control review.	Capital expenditure safety net.	No specific re-openers.	ESQCR (tree cutting), Traffic Management Act (TMA) costs.	TMA costs, interruptions, loss of meter work.
Ex-post adjustment (including logging up)	Companies receive additional income after the price control period.	Logging up of specified items.	Logging up of specified costs for Xoserve (central data service provider for Britain's gas market) developments.	Discretionary Reward Scheme	Discretionary Reward Scheme
Pass through	The price control allows full recovery of any costs in this category.	Ofgem license fee, business rates, pensions, etc.	Ofgem license fee, business rates, pensions.	Ofgem license fee etc, partial pass-through agreements for distributed generation (DG).	Ofgem licence fee, business rates, pensions.

14. Stephen Wright, Robin Mason, David Miles, 'A study into certain aspects of the cost of capital for regulated utilities in the UK', 2003

https://www.ofgem.gov.uk/ofgem-publications/50794/2198-jointregscoc.pdf

Type of study:	Report commissioned by the UK economic regulators and the Office of Fair Trading
Countries / region covered:	UK
Sectors covered:	Aviation, water services, gas and electricity, telecommunication, rail
Scope:	Cost of capital, with particular focus on cost of equity

Cost of capital

- The paper examines the components that build up the cost of equity and provides a comparison of asset pricing models for regulation (CAPM, nonlinear, conditional and multifactor models). A discussion of practical issues in estimation of asset pricing parameters for utilities, with focus on the estimation of the CAPM "beta" is provided.
- Discusses the case for consistency in setting the cost of capital: whether, even if regulators share the same central approach to estimating the cost of capital, uncertainty as to the true value may lead regulators to set different values in different industries.

Revenue adjustment mechanisms

- Discusses regulatory risk: whether there may be non-diversifiable risks associated with regulated industries that are not captured by standard measures of systematic risk.

A4.4 2010s

15. AER and ACCC, 'Regulatory Practices in Other Countries: Benchmarking Opex and Capex in Energy Networks', 2012	
https://www.accc.gov.au/system/files/Regulatory%20practices%20in%20other%20countries%20-%20Benchmarking%20opex%20and%20capex%20in%20energy%20networks.pdf	
Type of study:	Regulators' report
Countries / region covered:	Australia, UK, Ireland, New Zealand, Netherlands, Canada, US, Japan
Sectors covered:	Electricity, Gas
Scope:	Overview of practices employed by regulators to benchmark opex and capex and the extent to which cost benchmarking has contributed to the regulatory decision on revenue or price setting.

Capex and opex allowances

- **Benchmarking opex and capex**: Methods include: Partial Performance Indicators (PPI); Ordinary Least Squares; Corrected OLS (COLS); Data Envelopment Analysis (DEA); and Index-number-based Total Factor Productivity (TFP) analysis. Statistical techniques (DEA, OLS), more common for opex. Capex generally assessed by cost category using historical costs, PPI, and engineering-based analysis. PPI, including unit-cost analysis, also more common for benchmarking individual opex categories when there few observations (small number of businesses / time periods).

Building blocks versus TOTEX

- **TOTEX**: Opex and capex have mostly been benchmarked separately. In 2000, the DTe in NL used a DEA model that benchmarked TOTEX. From 2013, Ofgem intends to benchmark TOTEX.

16. Arcadis, 'Mission possible: successfully implementing TOTEX', 2014	
https://www.arcadis.com/media/C/5/D/%7BC5D3F5A2-2F2A-4195-BB0C-1DF72F349F42%7D8872_Totex%20EVP_WEB_LR.pdf	
Type of study:	Consultancy report
Countries / region covered:	UK
Sectors covered:	Infrastructure
Scope:	The report explores what can be done to successfully implement TOTEX

Building blocks versus TOTEX

- **TOTEX:** Combines asset-based (bottom up) with business-centric approach (top down). 'Top down' considers all external factors to understand all economic consequences of decisions.

17. Mathew Beech, 'It is the whole-life cost of an asset that is crucial, not just the initial outlay', 2015

https://utilityweek.co.uk/the-topic-totex/

Type of study:	Article
Countries / region covered:	UK
Sectors covered:	Electricity, gas, water
Scope:	Discusses Ofgem's decision to move to TOTEX regime under RIIO model

Building blocks versus TOTEX

- **TOTEX:** May incentivise utilities to replace historical installations with modern technology with lower opex. Also reduces the incentive to favour capex to increase asset value or to record spending as capex when it is not (which would result in time-consuming regulatory investigations).

18. CEER, 'CEER Report on Investment Conditions in European Countries', 2017

https://www.ceer.eu/documents/104400/-/-/44a08bad-efe7-01da-8b37-a3dd7edccfd5

Type of study:	Report
Countries / region covered:	Europe
Sectors covered:	EU, Norway
Scope:	Rate of return, RAB, and depreciation in EU countries and Norway

Description of regimes for controlling revenue

- **Cost-based**: Include ROR regulation and cost-plus regulation. Former guarantees firm a pre-defined rate of return on RAB. Latter adds pre-defined profit margin to firm's costs.
- **Incentive-based**: Financial incentives to induce firm to achieve desired goals (generally in form of efficient cost base). Company is allowed some discretion in how to achieve them.

Evaluation of regimes for controlling revenue

- **Efficiency**: Cost-based incentivises inefficiently expanding asset/cost base to increase profits.
- **Gold-plating**: Under cost-plus regulation, firm may have incentive to signal incorrect costs to the regulator or waste resources to increase the cost base (known as 'gold-plating').

Regimes used for controlling revenue

Table 5: Gas transmission regulatory regimes in some European countries

Country	Regulatory regime
AT	Combined model of price cap (opex) and rate-of-return (capex)
BE	Revenue cap + cost control incentives
CZ	Revenue cap
DE	Revenue cap (incentive-based)
DK	Other
EE	Rate-of-return
ES	Combined model. Revenue cap for investments before 2001. Standard costs in new investments and rate-of-return after 2001. Since 2014, in addition to standard costs, there is a new concept that considers continuity of supply.
FI	Revenue cap
FR	Revenue cap (incentive-based with pass through)
GB	Revenue cap based on rate-of-return with incentive-based regulation.
GR	Rate-of-return
HU	Revenue cap
IE	Revenue cap based on rate-of-return with incentive-based regulation.
IT	Combined model of price cap (opex) and rate-of-return (capex)
LT	Price cap
LU	Revenue cap
LV	Price cap
NL	Revenue cap
PL	Cost-of-service (with elements of revenue cap)
PT	Combined model of price cap (opex) and rate-of-return (capex)
SE	Revenue cap
SI	Revenue cap

Asset valuation

- **RAB valuation**: First table below displays countries adopting historical cost (exclusively) to determine initial RAB. Second table below shows approaches used to re-value gas transmission assets in five European countries (ie not historical cost).

Table 6: Countries exclusively using historical costs for initial RAB

Country	Electricity transmission	Electricity distribution	Gas transmission	Gas distribution
AT	N	Y	N	Y
BE	N	N	N	N
CZ	N	N	N	N
DE	N	N	N	N
DK	/	N	/	Y
EE	Y	Y	Y	Y
FI	N	N	N	N
FR	Y	Y	N	N
GB	N	N	N	N
GR	N	N	Y	N
HU	N	N	N	N
IE	Y	Y	Y	Y
IT	N	N	N	N
LV	Y	Y	Y	Y
LT	N	N	Y	Y
LU	N	N	N	N
NL	Y	Y	Y	Y
NO	Y	Y	/	/
PL	N	N	N	N
PT	N	Y	N	N
SI	Y	Y	Y	Y
ES	N	N	N	Y
SE	N	N	N	N

Table 7: Revaluation of gas transmission assets in some European countries

Country	Methodology	Source of market value or replacement cost
AT	Depreciated replacement costs	Replacement costs
BE	Depreciated economic replacement costs	Cost catalogue, internet prices
DE	Depreciated replacement costs	Data of a government agency

19. Glachant, Saguan, Rious, and Douget, 'Incentives for investments: Comparing EU electricity TSO regulatory regimes', Robert Schuman Centre for Advanced Studies, 2013

https://publications.europa.eu/en/publication-detail/-/publication/b17d95f8-1d4e-4bf1-a79b-0ae2361f8a26/language-en

Type of study:	Report
Countries / region covered:	Belgium, France, Germany, Britain, Netherlands
Sectors covered:	Electricity
Scope:	Properties of regimes and criteria to compare. Comparison of regimes of BE, FR, DE, GB, and NL. Potential outcomes of market integration.

Building blocks versus TOTEX

- **'Building blocks'**: Used in FR and BE. Capex and opex are separated.
- **'TOTEX'**: Used in DE and NL. Most investments included in revenue cap.
- **'RIIO'**: Used in GB. Benchmarking part of global evaluation of efficiency. Uses various tools.
- **Cost reduction**: More incentive to reduce costs in TOTEX than building blocks.
- **Risk**: TOTEX riskier for TSO because TSO operates in various environments that the benchmark is applied equally to.

Description of regimes for controlling revenue

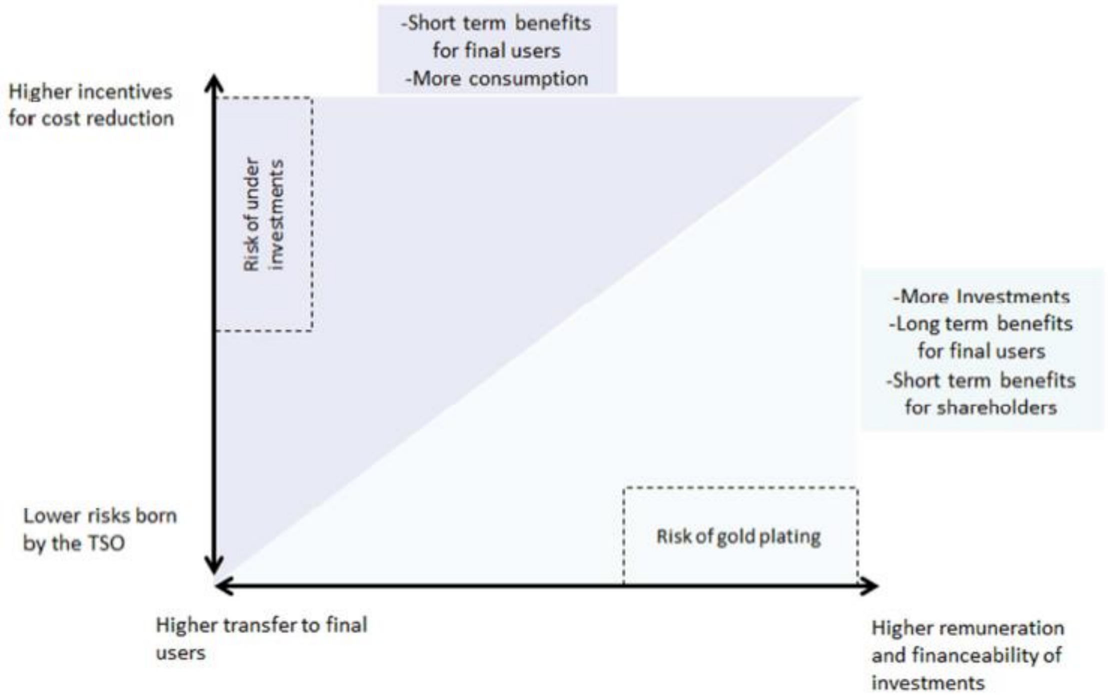
- **Cost-plus**: Firm recovers expenses plus a margin corresponding to a return on investment.
- **Forever price/revenue cap**: Regulator sets *ex-ante* a fixed (forever) price for the service.
- **Performance-based or sliding-scale regulation**: Share efficiency gains by comparing actual and expected costs and applying a rule. Balances properties of cost-plus with forever price cap at a level that depends on the applied sharing rule.
- **Menu of contracts**: Menu of contracts with various levels of incentives corresponding to different level of costs for the TNO. Network operator selects the most appropriate scheme.
- **Yardstick competition**: Compare costs and efficiency of each firm to performances of others and fix the company's revenues based on the average or best practice.

Evaluation of regimes for controlling revenue

- **Cost-reduction**: In ROR regulation, cost-reduction incentive comes from regulatory lags. In cost-plus regulation, there is a passthrough of any change in the costs of the company.
- **Moral hazard**: Cost-plus and ROR incentivise providing the regulator with incorrect information. Price/revenue cap solve this issue, as there is no cost revelation. Menu of contracts trades off cost revelation of network operator and incentive to reduce costs.

- **Efficiency versus risk and rent transfer versus financeability**: Trade-off between cost reduction incentives and risk borne by TSO. Trade-off between transfer of gains to users and risk of TSO financeability issues. The regime should be designed to fit priorities at the time.
  - Cost-plus: Limits monopoly rent and risks borne by TSO. (Bottom left.)
  - Forever price cap: Cost reduction incentives and no transfer. (Top right.)
  - Performance-based/menu: Intermediate. (Centre.)
  - Yardstick: Compromises efficiency and rents, but risky for TSOs. (Bottom centre.)

Figure 1: Trade-offs in regulatory design



Cost of capital

- **WACC adders**: Adders can incentivise *specific* investments if WACC too low. For example, if market forces result in a low WACC. Used in BE and FR.
- **Cost of debt**: Three design options. Embedded (or pass-through) debt design, used in DE and BE, implies less risk for TSO but less incentive to optimise financial structure. *Ex-ante* allowed cost of debt design, used in the NE and FR, has more incentive to optimise financial structure but more risks borne by TSO. GB is intermediate; indexed to market values.
- **Financeability check**: Used in GB to ensure investments financially feasible, given WACC.

20. First Economics, 'A review of recent UK price review innovations', 2015	
http://publicapps.caa.co.uk/docs/33/Regulatory%20innovations.pdf	
Type of study:	Consultancy report
Countries / region covered:	UK
Sectors covered:	Gas, Electricity, Water, Airports
Scope:	Reviews innovations that have appeared recently in price reviews carried out by Ofcom, Ofgem, Ofwat, ORR and the Competition Commission (CC) / Competition & Markets Authority (CMA). Also looks at Heathrow Airport's price cap.

Regulatory mechanisms

- **Broader outcome targets best:** Firms identify most efficient means of achieving outcomes. Review process also simpler (Ofwat had 11,000 schemes of 2,000 outputs to review in 2014, which fell to 500 performance commitments in 2015).
- **Is regulation needed for deviations in forecasted and realised outcomes?**
  - Ofwat's former chairperson ensured customers a 'gainshare' in addition to 'painshare' whilst working at two regulated firms before Ofwat, without regulatory intervention.
  - Anglian Water (2013): if RPI inflation < 3%, then full RPI increase in allowed revenues; if 3% < RPI inflation < 4.5%, then allowed revenues increase by 3% + (RPI inflation – 3% / 2; and if RPI inflation > 4.5%, increase in allowed revenues is subject to review.
  - ORR (2014): Produce an annual scorecard to calculate aggregate pain or gain experienced, then engage with a customer representative to discuss how to divide that pain and gain between customers and shareholders.

Building blocks versus TOTEX

- Removes 'capex bias', mentioned in various past reports by Ofgem and Ofwat.[97]
- Ofgem (2008, Electricity distribution price control review policy paper) said that "DNOs bear the full cost if they spend £1 of additional opex but only 29p to 40p if they spend £1 of additional capex". Ofgem's response was that companies will get a fixed z% share (usually 50-70%), regardless of whether the expenditure is opex or capex.

RAB

- **Indexing cost of debt:** Deviations from forecast controlled by indexing cost of debt, often assumed to be fixed to allowed rate of return.

[97] Ofwat (2014), Setting price controls for 2015-20 – risk and reward guidance. Ofgem (2009), Electricity distribution price control review methodology and initial results paper. Ofwat (2013), Setting price controls for 2015-20 – framework and approach: a consultation. Ofwat (2012), Consultation on wholesale incentives for the 2014 price review.

21. Lazar, J. Electricity Regulation in the US: A Guide. Second Edition. 2016

http://www.raponline.org/knowledge-center/electricity-regulation-in-the-us-a-guide-2/

Type of study:	Reference guide
Countries / region covered:	USA
Sectors covered:	Electricity
Scope:	Guide to US regulation. Chapter 8 discusses RAB, rate of return, opex, and taxes. Chapter 12 discusses drawbacks in traditional regulation. The rest of the document covers various other aspects of regulation.

Cost of capital

- Should be able to earn a reasonable rate of return on prudent investments and recover reasonable expenses.
- Rate of return must be fair relative to risk.
- Non-regulated services are riskier, so cross-subsidy problem.
- Rate Base = Historical cost minus depreciation + working capital – deferred tax and other adjustments.
- RoR set for each type of capital source; regulator sets the capital structure for which WACC is calculated. RoE from multiple models (DCF, Equity Risk Premium, CAPM).
- Recovery of carrying costs allowed: allowance for funds used during construction (AFUDC).

22. Mulder 'Tariff regulation and profitability of energy networks. A model analysis for TenneT TSO', 2010

https://www.acm.nl/sites/default/files/old_publication/bijlagen/7069_NMa_Working_Paper_Tariff_regulation_and_profitability_of_energy_networks.pdf

Type of study:	Working paper
Countries / region covered:	The Netherlands
Sectors covered:	Electricity
Scope:	Analyses impact of new regulatory framework on the long-term profitability of TenneT TSO, the operator of the high voltage electricity network in the Netherlands.

Evaluation of regimes for controlling revenue

- **Rent transfer versus investment**: Incentive-based regime is inadequate if there are big investment plans as it focuses too much on allocative efficiency at expense of investments.
  - NMa (2010) found the regime did not hinder investments. On average, return on capital in distribution companies exceeded opportunity costs of capital.

- But past investment programmes were modest.

Capex

- ***Ex-post***: TenneT TSO can receive additional revenues if it has realised considerable investment projects, dependent on the timing and size of investments. In the first year after realisation, 150% of these costs can be added to the revenues. This percentage is based on the idea that the investment was realised during the previous year while no revenues were received in that year. In the second and third year the additional revenues equal 100% of the costs. The size of these additional revenues is based on both opex and capex.
- **Capex allowances**: Future annual capex depends on the size of the assets in the base year (and the investments made since that year).

Opex

- ***Ex-post***: The size of the additional revenues (mentioned above) also factors in opex.
- Opex allowances: Future annual opex is related to the level in the base year.

Cost of capital

- **WACC**: Law says rate of return should not exceed opportunity costs of capital. This law and the need to finance investments mean that NPV of economic profit should be zero.
- **Debt**: Value determined by past value, new loans and instalments.
- **Equity**: Value depends on past value, net accounting profit, dividends, new deposited equity.
- **Gearing**: In the Dutch regulatory framework, a regulated firm is fully free to decide upon its gearing, which implies that it also must carry the risk of an inefficient financial structure.

Building blocks versus TOTEX

- **TOTEX**: Only 'considerable' investments treated separately from TOTEX, including separate efficiency assessment and the possibility to raise revenue during current regulatory period.

23. **Ofgem, 'Handbook for implementing the RIIO model', 2010**
https://www.ofgem.gov.uk/sites/default/files/docs/2010/10/riio_handbook_0.pdf

Type of study:	Regulator's report
Countries / region covered:	UK
Sectors covered:	Gas, Electricity
Scope:	This handbook is intended to give stakeholders a better understanding of how the RIIO model works in practice.

Building blocks versus TOTEX

- **Capex bias**: The same efficiency incentive rate is applied to opex and capex to reduce the risk that expenditure decisions may be distorted in favour of capital expenditure solutions.

Regulatory incentive mechanisms

- **Over-capitalisation**: Important not to set the lower bound in RIIO's efficiency incentive rate too low. Firm may spend money to increase RAB and not face exposure to the higher costs.
- **Which costs to include?** Maybe appropriate to exclude some costs from mechanisms.

Forward-looking revenue adjustment mechanisms

- **Indexation**: Calibrated at price control review, this is a provision that the firm's allowed revenue will change in line with price.
- **Volume driver**: Calibrated at price control review, this is a provision that allowed revenue will vary with volume/demand.
- **Revenue trigger**: Calibrated at price control review, this is a provision that allowed revenue will vary by a specified amount (or in a specified way) when pre-specified event occurs in the price control period.
- **Use-it-or-lose-it mechanism**: Calibrated at price control review, this is a provision that if revenue set aside for a specified purpose is not used as intended, the revenue will be adjusted to remove this allowance.
- **Why use these mechanisms?**
- To reduce risk and therefore to reduce WACC and consumer prices.
- To prevent firms from getting windfall gains due to luck rather than good management; consumers are thus protected from paying for the windfall gains.
- **Are there downsides?**
- Can undermine incentive for firms to mitigate efficiently against risks.
- Regulatory burden of designing, implementing, and managing the mechanisms.
- The added complexity to the regime diminishes its transparency.

Revenue adjustment mechanisms during and following price control period

- **Re-openers**: A provision that a specific portion of the revenue allowance will be reviewed and possibly adjusted during the price control period, on a forward-looking basis, following the trigger of exceptional events.
- **Pass-through items**: A provision the firm will be compensated for costs incurred on specific items, such as license fees.
- **Logging actual expenditures**: A provision the firm will be compensated for actual expenditure on certain activities, if the regulator determines the expenditure was

efficient.

- **Backward-looking adjustment**: Regulator benchmarks against other firms' actual expenditure on outputs and receives additional revenue proportional to its efficiency.

24. Ofgem, 'Regulating energy networks for the future: RPI-X@20, Current thinking working paper: Financeability', 2010

https://www.ofgem.gov.uk/sites/default/files/docs/2009/10/final-adaptability-paper_0.pdf

Type of study:	Regulator's report
Countries / region covered:	UK
Sectors covered:	Gas, Electricity
Scope:	This paper provides stakeholders with more detail of the regulator's current thinking on financeability.

Cost of capital

- **Cost of debt**: In future price controls, cost of debt will be backwards-looking, based on a long-term trailing average of forward interest rates, updated annually. Ofgem's says this provides a close fit to the price of debt typically achieved by network companies.
- **Cost of equity**: Ofgem uses a capital asset pricing model (CAPM) and checks the results against other methods, such as a dividend growth model and market to asset ratios (MAR).

Revenue adjustment mechanisms

- The paper discusses the allocation of risks between companies and customers using a bottom-up, a top-down and a hybrid approach.

25. Oxera, 'The opening regulatory asset base of the Dutch gas transmission system', 2011

https://www.acm.nl/sites/default/files/old_publication/bijlagen/4229_Regulatory%20Asset%20Base.pdf

Type of study:	Consultancy report
Countries / region covered:	Netherlands
Sectors covered:	Gas
Scope:	Advisory for NMa on the Dutch gas transmission system's opening RAB.

RAB

- **Replacement cost:** RAB costs incurred by a new entrant to the market.
- **Historical cost:** RAB costs incurred by firm.
- **Evaluation:**
  - **Subjectivity:** RC requires discretion and judgement in the valuation.
  - **Fairness:** HC argued to be fairer than RC.
  - **RC best if entry possibilities:** RC best if significant scope for new entry or pipeline-to-pipeline competition in the transmission network.
  - **Does methodology matter?** If there is concern with infrastructure-based competition, changing the structure of charges (or the mechanisms for allocating capacity) may be a more proportionate policy response than amending the RAB valuation methodology.

26. Oxera, 'The CAPEX factor: dealing with uncertainty in setting CAPEX allowances', 2016

https://www.oxera.com/Latest-Thinking/Agenda/2016/The-CAPEX-factor%E2%80%94part-1-dealing-with-uncertainty-i.aspx

Type of study:	Consultancy report
Countries / region covered:	UK
Sectors covered:	Transport, electricity
Scope:	Considerations in setting capex allowances, given cost uncertainty.

Capex allowances

- **Capex uncertainty:** Difficult to forecast for long projects. One-off nature of projects means regulators inexperienced. Project scope can change. Solutions include:
  - Contingency margins: Lower risk of cost overrun. Can be project-specific or general. Must not weaken efficiency incentives or reward when risks do not materialise.
  - Flexible cost allowance: Record small deviations at end of control period. For large deviations, reopen price control and adjust parameters. Distorts efficiency incentives. Office of Rail and Road (ORR) and Civil Aviation Authority (CAA) allowed adjustments at early developmental stage of projects; most increased in cost.
- **Non-recurring capex:** Fixed regulatory periods incentivises efficiency for recurring capex (eg capital maintenance). Less so for other capex. Bowe review[98] suggests UK DfT to remove enhancement spend from regulatory settlement.
  - Funding of enhancement projects outside periodic review process was used in Crossrail and Thameslink. Criteria for exclusion not clear.
- **Outsourcing:** Outsourcing large projects to third party could improve capex efficiency through competition and reduce risks faced by regulators. Examples: Thames Tideway

[98] Department for Transport (2015), 'Report of the Bowe Review into the planning of Network Rail's Enhancements Programme 2014-19', Cm 9147, November, p. 40, para. 6.22.

project; competitive tendering in onshore electricity transmission projects by Ofgem.

Building blocks versus TOTEX

- **TOTEX:** Does not require detailed review of cost forecasts for individual projects. More stable over time and more comparable between companies. Does not directly tackle cost uncertainty.

27. Oxera, 'Ofwat's final methodology: now for implementation', 2013

https://www.oxera.com/getmedia/23105227-c900-4f89-b890-ede7297ad104/Implementing-Ofwat-s-methodology.pdf.aspx?ext=.pdf

Type of study:	Consultancy report
Countries / region covered:	UK
Sectors covered:	Water
Scope:	Overview of Ofwat's main decisions on the 2014 price review

Building blocks versus TOTEX

- **TOTEX:** Following Ofgem, Ofwat will use a TOTEX approach. It will establish ranges ('cost corridors') or thresholds ('cost ceilings') for the efficient level of TOTEX. Companies with TOTEX proposals outside of the range will be subject to greater scrutiny by Ofwat.

28. Oxera, 'Regulatory regimes at airports: an international comparison', 2013

https://www.oxera.com/Oxera/media/Oxera/downloads/reports/Regulatory-regimes-at-airports_1.pdf?ext=.pdf

Type of study:	Consultancy report
Countries / region covered:	UK
Sectors covered:	Airports
Scope:	Review of economic regulatory regimes at seven international airports. Key features of the regimes, practical applications, and outcomes.

Evaluation of regimes for controlling revenue

- **Regulatory burden under price cap:** Regulator must determine reasonable cost of capital and efficient level of costs. Not directly observable, meaning intense scrutiny of capex and general market data required, which can be considerably costly for the firm and the regulator.

29. Perez-Arriaga, 'Regulation of the power sector', 2013
https://www.iit.comillas.edu/publicacion/mostrar_publicacion_libro.php.en?id=211

Type of study:	Book
Countries / region covered:	Various
Sectors covered:	Electricity, Gas
Scope:	Covers various aspects of power-sector regulation.

RAB

- **Existing assets:**
  - **Book value:** Sum originally paid for the investment, subtract cumulative depreciation.
  - **Reproduction cost:** Cost of reproducing the investment today.
  - **Market value:** Value the assets would command if sold on the market.
  - **Replacement cost:** On the grounds of replacement cost or the new replacement value (NRV), ie the cost involved in replacing existing assets with new upgraded facilities available with today's market technology and costs, but which serve the same purpose.
- **Inclusion of new assets in the RAB:**
  - ***Ex-ante*:** Forecasted future capex included in the RAB, determining MAR. Company incentive to overestimate capex to raise MAR. Investment cost benchmarking can prevent this. Sliding-scale mechanism incentivises accurate capex projections by allowing firm to retain part of gains from efficient investment.
  - ***Ex-post*:** An *ex-post* review is used if a significant individualised investment not undertaken in the expected timeframe, eg transmission assets. Firm allowed extra revenues if it finished early or is penalised if delayed.
  - ***Ex-ante/ex-post*:** *Ex-post* review decides which investments were necessary and allow those assets to be included in the RAB, replacing assets included in the RAB *ex-ante*.

Cost of capital

- **Cost of equity estimation:** Estimated from securities market information on similar companies.
- **Usually $R_{debt} < R_{equity}$:** Shareholders more exposed to financial failure than lenders.

Setting the efficiency/productivity factor

- **Benchmarking:** Distance between firm's productivity and its projection on frontier measures its inefficiency. The higher the inefficiency, the higher the productivity factor X.
  - **DEA:** Non-parametric. Efficiency factor (between 0 and 1) is ratio between weighted sum of outputs and weighted sum of inputs. Linear optimisation problem solved to calculate the weights and efficiency factor for each firm.

- **COLS:** Parametric. Plot firms' total costs against output. Use OLS to fit a regression line. A line with the same gradient is plotted through the lowest-cost firm's data point. Vertical distance between firm's data point and the fitted line represents its efficiency.
- **SFA:** Parametric. Like COLS but considers role of stochastic errors.

Description of types of regulation

- **Cost-based:** The formula below is typically used for ROR regulation.

$$AR = TC = O\&M + DP + s \times RB + TAX - ADR \qquad (4.1)$$

where

AR is the allowed revenues,
TC is the total cost of service,
O&M is the allowed operating and maintenance costs,
DP is the depreciation expenses on the company's gross assets,
s is the allowed rate of return,
RB is the rate base, a measure of the value of the company's investment, calculated as its net assets, defined to be its gross assets less depreciation,
TAX is the taxes for which the company is liable, and
ADR is the additional revenue.

- **Incentive-based:** Midway between cost-of-service regulation and deregulation.

Price cap: $\bar{P}_{m,t} = \bar{P}_{m,t-1} \times (1 + \mathrm{RPI}_t - X) \pm Z$

Revenue cap: $R_t = R_{t-1} \times (1 + \mathrm{RPI}_t - X) \pm Z$

- **Performance-based:** May be secondary objectives (in addition to primary cost incentive in incentive-based regulation). Service quality, energy-efficiency innovation, etc.
- Sliding-scale regulation:

$$s_t = s_t + h(s^* - s_t) \qquad (4.8)$$

where

- h is a constant parameter ranging in value from 0 to 1 and established by the regulator,
- s_t is the rate of return that the company would obtain in year t as a result of the tariffs set in the current rate case and prior to the application of this adjustment, and
- s^* is the target rate of return.

Evaluation of regimes for controlling revenue

- **Efficiency:** ROR formula considers allowed opex, not actual. Incentivises efficiency. If mid-term tariff revisions are allowed and the regulator adjusts rate of return, this incentive is lost.
- **Information asymmetry:** ROR regulator must request lots of data. Costly burden.

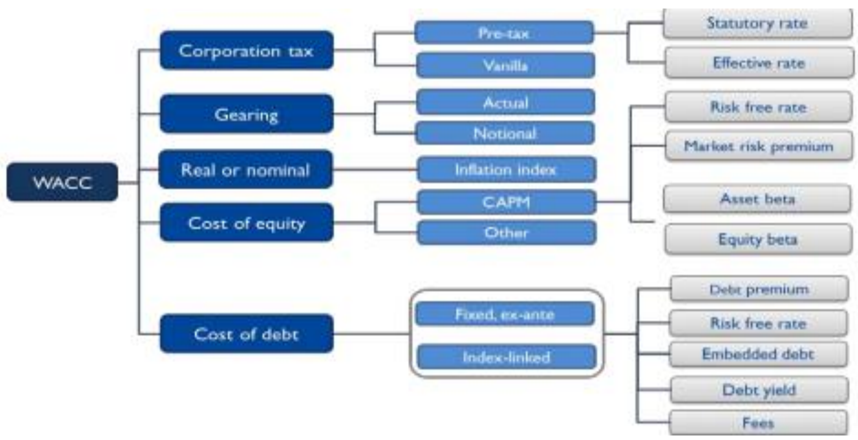
- **Risk:** ROR covers costs, reducing TSO risk. Incentive-based regulation that insufficiently adjusts to *ex-post* costs carries risk. Sliding-scale shares risk between firm and consumers.
- **Rents:** Incentive-based involves *ex-post* lowering of revenues based on actual costs, passing the efficiency gains to consumers in the next regulatory period.
- **Regulatory burden:** Incentive-based has been useful in countries with undeveloped auditing systems, where state-owned companies were divided and privatised.

30. UK Regulators Network, 'Cost of Capital - Annual Update Report', 2017
http://www.ukrn.org.uk/wp-content/uploads/2017/05/20170503-UKRN-Annual-WACC-Comparison-Report_FINAL.pdf

Type of study:	Information paper
Countries / region covered:	UK
Sectors covered:	Aviation, gas and electricity markets, water, transport, communication
Scope:	Provide an update on the cost of capital decisions taken by regulators over the last year. The paper also provides a summary of the most recent decisions on the weighted average cost of capital (WACC) by each regulator and an overview

Cost of capital

- The paper starts off with providing reasons why cost of capital will vary across different sectors despite using a similar method (eg Capital Asset Pricing Model).
- The paper subsequently discusses the weighted average cost of capital (WACC) and provides a description of the individual components and differences across regulators.



- A timeline of upcoming price reviews together with a section on past decisions on cost of capital components in recent principal controls is presented.
- The appendix contains a summary of each regulator's duties regarding financeability in the context of their other responsibilities and a detailed description of the components of cost of capital.

A5 Country fact sheet template

COUNTRY AND FLAG		
Regulatory, market and policy framework		
Regulator	Name	
TSO(s)	Name	
Customer mix	Residential/commercial	%
	Large industrial	%
	Power generation	%
Ratio of transit to national flows	Question 1.7	
Network age and length	Pipeline length	km
	Original operation	year
Regulatory governance and process		
Entity that establishes the methodology and sets allowed/target revenues	Question 2.2 – 2.4	
Length of revenue setting process	months	
Parties that can appeal NRA-determined revenues	Question 2.14	
Type of appeal that is allowed	Question 2.17 Limited merits / full merits / procedural review	
Overall framework for setting allowed revenues		
Type of regulation	Question 3.1	
Approach to assembling the cost base	Question 3.2	
Duration of regulatory period	Question 3.3 / years	
Determining and setting operating expenditures		
Cost categories partially or fully passed through	None / items	
Methods and approaches to assessing and setting opex allowances	Question 4.7 and 4.10	
Inclusion of efficiency or productivity improvements	Question 4.11 Yes/No	
Efficiency factors used in most recent regulatory period	Question 4.12	
Treatment of gas shrinkage	Question 4.13 Describe	
Determining and setting capital expenditures		
Methods and approaches to assessing and setting allowances	Question 5.3 and 5.7	
Use of uncertainty mechanisms	Question 5.8	

<table>
<tr><td colspan="3">COUNTRY AND FLAG</td></tr>
<tr><td>Inclusion of efficiency or productivity improvements</td><td colspan="2">Question 5.9
Yes/No</td></tr>
<tr><td>Efficiency factors used in most recent regulatory period</td><td colspan="2">Question 5.10
%</td></tr>
<tr><td>Use of ex post reviews before rolling capital expenditure or assets into the RAB</td><td colspan="2">Question 5.13</td></tr>
<tr><td>Use of tendering for large system expansions</td><td colspan="2">Question 5.15</td></tr>
<tr><td colspan="3">Regulatory asset base (RAB)</td></tr>
<tr><td>Method used for setting the opening asset value (at the time of establishing the new regulatory framework)</td><td colspan="2">Question 6.1</td></tr>
<tr><td>Depreciation of closing asset value as a single asset or as separate asset categories</td><td colspan="2">Question 6.3</td></tr>
<tr><td>Revaluation of the RAB</td><td colspan="2">Questions 6.4 and 6.5</td></tr>
<tr><td>Major assets included in the RAB</td><td colspan="2">Question 6.9</td></tr>
<tr><td>Inclusion and treatment of linepack</td><td colspan="2">Question 6.10</td></tr>
<tr><td>Inclusion and treatment of working capital</td><td colspan="2">Questions 6.3 and 6.14</td></tr>
<tr><td>Timing of rolling investments into the RAB</td><td colspan="2">Question 6.17 and 6.18 (when assets are included upon commissioning or becoming operational)</td></tr>
<tr><td colspan="3">Depreciation</td></tr>
<tr><td>Method</td><td colspan="2">Question 7.1</td></tr>
<tr><td rowspan="4">Asset lives (for major asset groupings)</td><td>Pipelines</td><td></td></tr>
<tr><td>Compressors</td><td></td></tr>
<tr><td>Controllers/metering stations</td><td></td></tr>
<tr><td>SCADA, telecoms</td><td></td></tr>
<tr><td colspan="3">Cost of capital and financeability</td></tr>
<tr><td>WACC method</td><td colspan="2">Pre-tax/vanilla/post-tax, real/nominal (Questions 8.2 and 8.5). Also, state if an allowed WACC is not set – question 8.1</td></tr>
<tr><td rowspan="2">WACC value set in the two most recent regulatory periods</td><td>Previous regulatory period</td><td>Current regulatory period</td></tr>
<tr><td>%</td><td>%</td></tr>
<tr><td>WACC premium for specific investments or risks</td><td colspan="2">Questions 8.8 and 8.9</td></tr>
<tr><td>Primary (or only) methodology for setting the cost of equity</td><td colspan="2">Question 8.10</td></tr>
<tr><td>Method for setting the risk-free rate (RFR)</td><td colspan="2">Question 8.12</td></tr>
<tr><td>Method for setting the equity or market risk premium (MRP/ERP)</td><td colspan="2">Questions 8.13 – 8.15</td></tr>
<tr><td>Method for establishing the equity beta</td><td colspan="2">Question 8.16</td></tr>
<tr><td rowspan="2">WACC parameters
(RP = Regulatory Period
CoE = Cost of Equity)</td><td colspan="2"><table><tr><td></td><td>RFR</td><td>MRP</td><td>Equity beta</td><td>Asset beta</td><td>CoE</td></tr><tr><td>Prev. RP</td><td></td><td></td><td></td><td></td><td></td></tr></table></td></tr>
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COUNTRY AND FLAG						
	Current RP					
Method for setting the cost of debt	Questions 8.19 – 8.22					
Inclusion of debt issuance costs	Yes/no (question 8.23)					
Cost of debt parameters	***Previous regulatory period***	***Debt premium (if relevant)***	***Cost of debt (net of issuance costs)***	***Debt issuance costs (if relevant)***		
	Previous regulatory period					
	Current regulatory period					
Gearing approach	Actual/notional					
Gearing level	***Previous regulatory period***	D/D+E				
	Current regulatory period	D/D+E				
Financeability assessment	Questions 8.28 – Question 8.30					
Other regulatory mechanisms (revenue adjustments and incentives)						
Treatment of accumulated over or under-recoveries of revenues	Questions 9.2 - 9.4					
Adjustment mechanisms for differences between forecasted or allowed <u>operating expenditures</u> and realised spend	Questions 9.5 – 9.8					
Adjustment mechanisms for differences between forecasted or allowed <u>capital expenditures</u> and realised spend	Questions 9.5 – 9.6, 9.9 – 9.10					
Treatment of capital expenditure deferrals	Questions 9.11 – 9.13					
Other revenue adjustment or incentive mechanisms	Add any other mechanism countries may have and add performance regime here if they have one (ie questions 9.15 – 9.19)					
Regulatory reporting						
Requirement for and frequency of regulatory reporting	Question 10.1					
Coverage of regulatory reports	Question 10.3					
Purpose of regulatory reports	Question 10.6					
Requirement for reconciliation with audited financial statements	Yes/no (Question 10.5)					
Key information sources						
Links to: - *NRA site* - *Methodology (if provided in question 2.6)*						