Smarter incentives for transmission system operators

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TenneT

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Volume 1

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Contents

Figures and tables

Executive Summary

Most regulatory systems for transmission operators in Europe focus strongly on the construction and remuneration of assets. However, the role of a transmission system operator (TSO) is much broader than this. Incentives provided by the regulatory system need to reflect that breadth. TSOs need to balance several inputs and outputs in a way that, ideally, would be beneficial to society. In order to give the TSO the opportunity to maximise 'social welfare',[1] financial incentives should cover all their relevant inputs and outputs. In turn, these incentives should be balanced and aligned in a manner explained below.

This report provides a high-level review of existing TSO incentives, and proposes two alternatives for regulatory reform that could improve the performance of TSOs in the delivery of their main roles or functions.

The main roles of TSOs considered in this report are as follows.

- The role of asset planning, construction, maintenance and replacement means that TSOs should provide an appropriately sized and planned infrastructure to enable electricity transmission.
- The role of system operation (SO) means keeping reserves in place and executing efficient redespatch.
- The role of a market facilitator means helping to create the internal energy market—in particular, by facilitating cross-border trading of electricity.
- An increasingly important role of the TSO is that of a data facilitator. Traditional as well as new market participants (distributed generators, prosumers, aggregators, and others) will require access to high-quality data on the status and performance of the electricity system.
- From an environmental perspective, the key role of a TSO is to facilitate the integration of an increasing amount of renewable electricity production.

A review of the regulatory approaches in Europe, the USA and Australia, undertaken for this study, shows that, in practice, many approaches are used. Similarly, there is a wide range of academic literature on the subject of regulation. Nevertheless, most practical approaches to economic regulation of utilities correspond broadly to one of three stylised regulatory archetypes:

1. **input-based regulation**: the costs of the regulated company are reimbursed. While this approach is pragmatic and simple, it generally does provide strong incentives for efficiency;
2. **revenue (or price) cap regulation**: the company is given a cost budget for a certain period that is delinked from actual costs. Since the company is allowed to keep some or all of the cost outperformance,[2] the incentive to control costs is stronger than under input-based regulation;
3. **output-based regulation**: parts of the allowed revenue of the regulated company are not set according to its costs, but according to the value to customers created by the services provided. As long as this value can be

[1] In this report, social welfare encompasses reductions in operating expenditure (OPEX) (including system operation costs) and in capital expenditure (CAPEX) relative to a 'business as usual' scenario, as well as the increase in value generated through the provision of additional services associated with the traditional role of TSOs.
[2] Cost outperformance means that a firm manages to have lower costs than target. In an incentive scheme, this means that the firm can keep some of the savings as extra profit.

measured, this regulatory approach offers an alternative to more traditional approaches. This is because it gives an incentive to control costs and to provide outputs that can approximate the incentives of a well-functioning market.

In order to derive prototypes for future regulatory systems, the elements found in the international review of regulation undertaken for this study were evaluated against several criteria for good regulation. These criteria included whether the regulation creates an efficiency or output incentive, and aligns incentives between a company and its customers; whether it is technology-neutral; whether there is an efficient sharing of risk; whether there might be implementation challenges; and the extent to which the regulation promotes financial stability for the TSOs.

Taken together, all regulatory measures should be balanced. An example of an unbalanced incentive would be where there is a strong incentive to control one category of costs and only a limited incentive to control another. This could result in a regulated company economising on one set of costs while still increasing costs overall. A balanced incentive would cover both categories with an incentive of similar strength.

Aligned incentives ensure that the interests of consumers and companies are both met. Revenue cap regulation is a good example because, by introducing the opportunity for the company to outperform against a fixed budget, an incentive is created to save costs. This can be in the interest of consumers, provided that quality of service is maintained. Output-based regulation also aligns incentives by remunerating companies according to a share of the value they create for consumers.

When analysing the situation in Germany and the Netherlands, Oxera found that some elements of revenue cap and output-based regulation are used already. However, these regulatory systems are inconsistently applied across cost categories. Also, some outputs are regulated by inflexible rules that do not necessarily allow TSOs to optimise their provision in order to minimise costs overall. The proposed regulatory prototypes in this report are intended to enable these shortcomings to be overcome.

Based on the evaluation of existing regulatory elements, two prototypes for future regulatory systems were designed.

- **Prototype 1** builds on the current regulatory system, but introduces an operating expenditure (OPEX) budget to keep written-off assets in operation for longer. It also introduces a revenue cap incentive to reduce system operation SO costs.
- **Prototype 2** introduces a new capitalisation rule that treats all spending the same, whether for assets such as new power lines, or for OPEX such as the procurement of flexibility services. Thereby, a degree of technological neutrality is ‘hard-wired’ into the system. Because a fixed general share of capital expenditure (CAPEX) to OPEX is assumed, this approach is referred to as the ‘fixed CAPEX/OPEX share’. Prototype II also proposes that all costs (including SO costs) be regulated under one unified regulatory formula. This equalises the treatment of all costs, and hence fully balances incentives.

For both prototypes, we suggest output-based incentives for market facilitation, data facilitation and environmental protection.

Indicative quantitative analysis showed that the prototypes can deliver more aligned and balanced incentives than the current regulatory system in Germany and the Netherlands. Because of these improved incentives, both consumers and TSOs could benefit—consumers, because of opportunities to further reduce costs; and TSOs, because they can benefit from outperformance incentives.

To summarise, this report puts forward two suites of balanced and aligned incentives for TSOs, and quantifies the impacts of these approaches through illustrative modelling. These incentives could contribute to a greater alignment of interests between TSOs, regulatory authorities, and customers as they help to overcome any bias towards CAPEX-intensive solutions and provide incentives to reduce total expenditure (TOTEX) (including SO costs). Similarly, an increased emphasis on outputs could help to enhance outcomes for customers.

1 Introduction

Most regulatory systems for transmission operators in Europe focus strongly on the construction and remuneration of assets; hence, there is a general sense that these systems might incentivise the construction of assets.

However, the role of a transmission system operator (TSO) is broader than building assets, and the incentives provided by regulatory systems need to reflect this. Ideally, a TSO should be incentivised to balance several inputs and outputs in a way that is beneficial to society. In economic terms, regulatory best practice suggests that TSOs should optimise overall welfare.

Against this context, TenneT and Oxera have been considering the long-term development of the regulatory system for electricity TSOs in Germany and the Netherlands.

Some broader incentive schemes that go beyond providing a return on assets already exist; for example, the bonus-malus system on balancing services in Germany or the various systems of quality of service regulation. However, in Germany and the Netherlands, many of a TSO's inputs and outputs are either not incentivised at all, or are governed by inflexible legal rules or targets.

This study considers what a system of 'smarter' incentives for TSOs could look like. How could the regulatory system be improved to create an integrated internal energy market and to facilitate the energy turnaround,[3] while maintaining the high security of supply standards that customers in Germany and the Netherlands have come to expect?

The report is structured as follows.

- Section 2 identifies the current and future roles of a TSO that could be enhanced through the introduction of regulatory incentives.
- Section 3 presents the regulatory theory in non-technical terms, and sets out the basic properties of efficient incentive systems.
- Section 4 presents the results of a comprehensive desk-research exercise, giving an overview of current regulatory mechanisms in Europe and elsewhere, and highlighting trends in applied regulation.
- Section 5 suggests two prototypes for the design of a future regulatory system.
- Section 6 presents the results of the indicative impact analysis.
- Section 7 concludes.

[3] The planned transition in Germany to a low-carbon, environmentally sound, reliable, and affordable energy system.

2 The role of a TSO

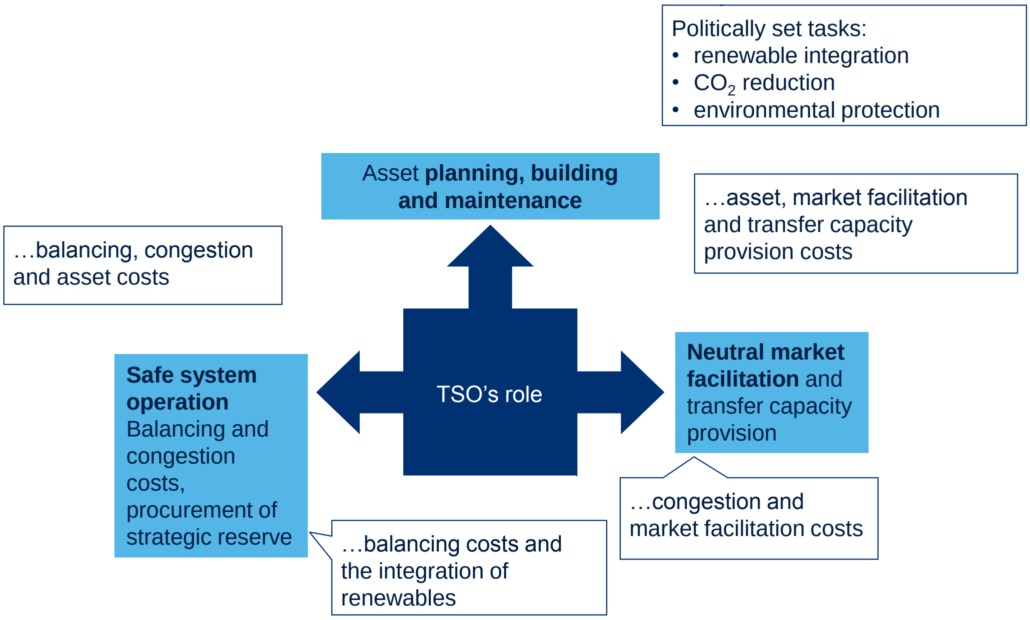
In order to guide the development of a future incentive system for TSOs, it is first necessary to consider the roles that they are expected to fulfil. This section provides a high-level description of the current and potential future roles of TSOs in order to motivate the selection of an applicable incentive scheme.

With the policy objective of electricity decarbonisation, new demand and generation resources are being developed. The requirements for managing these and coordinating the availability of network capacity are expected to motivate TSOs to adopt digital control and monitoring technologies. As a result, the ‘outputs’ or services that would be expected from a typical European TSO may be expected to evolve. In this section, we therefore draw a distinction between their current and future roles.

2.1 The current role of a TSO

At present, a TSO is required to deliver several outputs, as shown in Figure 2.1 and described in more detail below.

Figure 2.1 Current role of a TSO



Source: Oxera.

2.1.1 Asset planning, building and maintenance

TSOs are tasked with planning, building and maintaining the assets that are needed for a secure system.

With the future location of plants, and their loads and capacities, being partly uncertain, planning the grid is a complex task. Similarly, with new information about the location of generation capacities and technical possibilities (smart solutions) becoming available over time, the network development plan has to be updated constantly.

When it comes to investments in tangible assets, a TSO needs to control construction costs and avoid cost overruns. Building the assets within a reasonable timescale is sometimes a challenge because of lengthy and uncertain approval procedures.

Once the assets are constructed, a TSO needs to choose the right level of maintenance in order to minimise overall life-cycle costs. This decision is linked to the decision on when to replace ageing assets. On the one hand, assets should be used as long as they are still functional, in order to delay reinvestment costs for as long as possible. On the other hand, a failure is more probably when using older assets, which can increase their maintenance and refurbishment costs. The TSO should ideally balance the costs and benefits optimally against one another. By and large, existing regulatory systems tend not to do this, and so incentivise early reinvestments to avoid higher maintenance costs.

2.1.2 Safe system operation

Safe system operation involves the different types of reserve, such as balancing, (renewable) curtailment and strategic reserve on the one hand, and redespatch on the other; the main difference between them being that:

- reserves are used to balance supply and demand in the overall system;
- redespatch is used locally to resolve congestions so as to balance supply and demand because there is insufficient transfer capacity in the network.

Reserves and balancing

Balancing means that the TSO is actively monitoring the stability of the electricity system at all times. Where necessary, the TSO will employ a range of reserves in order to guarantee system stability: if too little reserve is procured, system stability cannot be guaranteed; if too much, the costs are inefficiently high. Reserve size is usually set by rule of thumb. For example, the primary reserve (the fastest reserve class in Central Europe) is set at the size of the largest expected double-incident (N-2) of generation units; namely, ±3,000MW.

TSOs organise several single-buyer markets through which they procure reserve services. These differ mainly in the timescales over which the reserves are available. To procure the service efficiently, TSOs buy short-term reserve in auctions separately to those for long-term reserve. This form of price discrimination allows the TSO to meet its overall reserve requirement at a lower cost. On the other hand, to ensure a sufficient number of competitors in each market, there is a limit to how many separate procurement markets can be established.

Redespatch

In the liberalised wholesale electricity market, electricity can be traded freely between producers and retailers throughout Germany and the Netherlands. However, owing to network constraints, not all of these electricity deliveries may be feasible. It then becomes the task of the TSO to adjust the despatch schedule to make it physically feasible. To compensate plants and load such that they adjust their production and consumption schedule upwards or downwards, they are paid redespatch costs.

2.1.3 Market facilitation

In this report, ‘market facilitation’ refers to TSOs enabling welfare-enhancing transactions in electricity wholesale to take place.[4]

In terms of the current role of the TSOs, this objective is typically manifested in a requirement to offer as much cross-border transfer capacity as possible, thereby allowing greater opportunities for regional and international trade.

The TSOs facilitate the geographic widening of electricity markets in several ways. Within the borders of Germany and the Netherlands, market facilitation is maximised by letting all suppliers and retailers trade freely on the futures, day-ahead and intra-day markets. This maximum of market facilitation leads to the need for redespatch (see above).

By physically creating transfer capacities and then allowing the electricity exchanges to use this capacity efficiently, the TSOs play a major role in facilitating transactions between national markets.

2.2 The future role of a TSO

In addition to the roles noted above, a TSO is expected to face changing and new demands, driven by three main wider trends.

1. The expected increase in the share of renewables, which could lead to the need for transmission capacity over and above the lines that are already planned; and reduce the demand for transmission services, if storage technologies (e.g. batteries and power to gas) become cheaper and are increasingly used instead of new lines (depending on the efficient scale of these technologies).

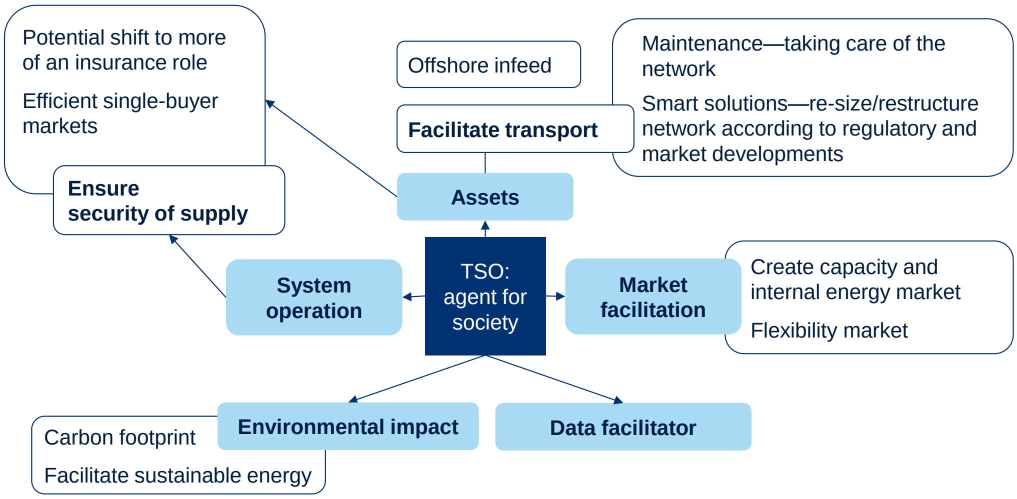
2. European policy pushing for further market integration.

3. The digitisation of energy systems, which will allow for networks to be monitored and steered more closely. It will also further reduce the transaction costs of electricity trades (flexibility markets).

Figure 2.2 gives an overview of the possible future role of a TSO.

[4] In a free market, transactions take place only when they are value- (welfare) generating. Therefore, in general, allowing as many transactions as possible will increase welfare. However, from a policy point of view, it should be kept in mind that electricity trading between two markets will increase prices in one market.

Figure 2.2 Future role of a TSO



Source: Oxera.

These future developments pose some challenges for TSOs, given the uncertainty around their extent and impact. For the next ten years or so, rapid network expansion would be needed to ensure that the system can cope with increasing amounts of intermittent energy. However, thinking further ahead, the TSO role is likely to change. In particular, there is uncertainty about how demand for electricity transmission will develop, with more distributed generation and possibly distributed storage. Nevertheless, some current tasks are likely to remain and others may evolve, as follows.

- **Facilitating the transport of electricity** and maintaining the grid will remain important. Here, managing the infeed from offshore wind could be particularly important. In addition to maintaining existing infrastructure, the TSOs may be transforming the network, rather than necessarily expanding it. This could mean swapping old infrastructure for new smart solutions, making changes to protect the environment or visually improve landscapes, or even scaling back infrastructure depending on technological progress and demand forecasts in certain areas of the grid.
- **Ensuring security of supply** and grid availability is also likely to remain a core task for the TSOs. However, depending on the development of distributed generation, consumers' reliance on the grid may significantly decrease in the long term. In this case, the electricity network may still be a critical infrastructure, but possibly as back-up, rather than constantly serving all consumers.
- **Market facilitation** will be a major task for the TSOs going forward.[5] The European Commission will continue to push for further geographic integration of the European electricity wholesale market. As such, the provision of international transfer capacities will gain in importance.

  In addition, the TSOs will have a role in providing market facilitation to increase the depth of electricity markets by bringing industry and prosumers into flexibility markets. The data backbone needed for this will be provided by the TSOs (at least in part), and these are considered to be neutral and competent institutions when it comes to market facilitation.

[5] In section 5.5 we set out some suggestions for regulatory change to incentivise this role.

- **Facilitating data usability and transparency** is a new task for the TSOs. In theory, several entities might viably carry out this task, and the TSOs are certainly well suited to doing so. This role is connected to market facilitation since allowing access to usable electricity data creates the potential for new markets as business ideas emerge based on this data. Here, a level of transparency would be needed in order to protect customers and commercially sensitive data, while allowing the efficiency benefits of data transparency.
- **Facilitating sustainable energy** and making a positive environmental impact will be part of the TSO role in the long term. This role overlaps with many other areas, including facilitating the renewable energy infeed, reducing the carbon footprint, or moderating the impact of cables in protected areas.

2.3 Overall balancing of outputs and costs

Apart from performing efficiently the tasks described above, the dependencies between the outputs and the costs should ideally be considered in order to minimise overall costs. Examples are as follows.

- If more resources are used to provide more lines (assets), the costs for redespatch (SO) will decrease. Similarly, more renewable energy supply infeed (RES infeed) can be taken up and more transfer capacity can be provided (market facilitation).
- If more transmission capacity is devoted to border transfer capacity, less RES infeed can be absorbed. At the same time, SO costs are likely to increase.
- The decision on whether assets should be replaced or maintained comes down to whether it is cheaper to replace an asset or to accept higher maintenance and outage costs.
- Some network problems can be solved by alternative technical network solutions. If more capacity is needed at some point in the network, additional power lines can be built. Alternatively, and increasingly in light of technical progress, other solutions such as smarter steering of the network or batteries might be used as well. Another alternative is the procurement of flexibility.

3 Regulatory theory

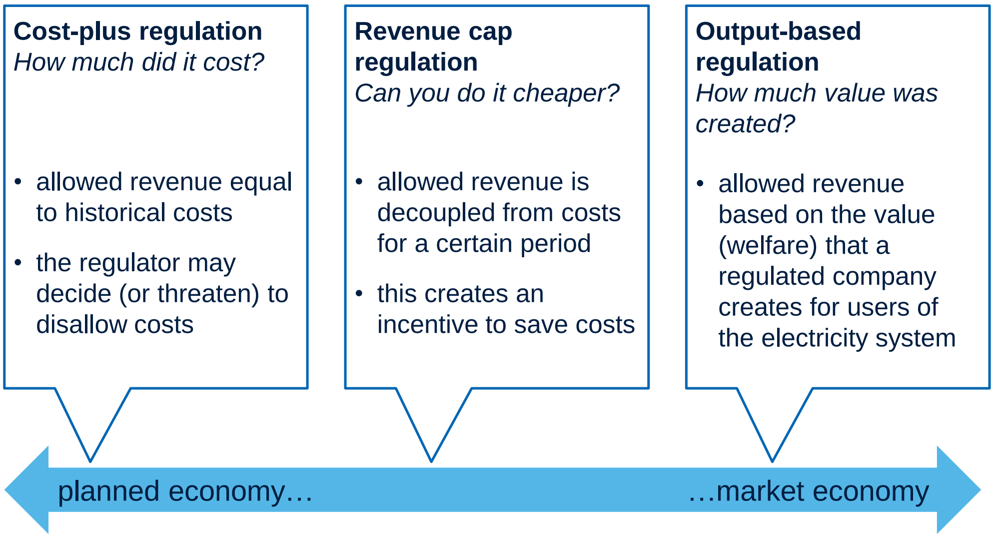
Next to the well-known cost-plus and revenue cap regulation, output-based regulation is increasingly being recognised as a practical approach to the regulation of utilities and network infrastructures.

This report applies and adjusts revenue cap regulation for TSOs and extends this to encompass elements of output-based regulation.

3.1 Regulatory archetypes

Figure 3.1 summarises the regulatory archetypes. As indicated by the arrow below, regulation rarely comes in a 'pure' form; rather, regulatory systems typically encompass a combination of cost-plus, revenue cap and output-based principles. Output-based regulation provides greater flexibility to design incentives to control costs and to provide the desired level and quality of services in a manner that more closely approximates the incentives of a well-functioning market.

Figure 3.1 Regulatory archetypes



Source: Oxera.

Revenue cap regulation is a form of incentive regulation,[6] and is usually contrasted with rate-of-return regulation or cost-of-service regulation. Under these types of cost-based regulation, allowed revenues are linked directly to the underlying costs: actual costs are passed through into the allowed revenues without long delay.

Two main limitations of such systems are well known:

- if the firms pass through the costs they incur, the incentives to avoid costs and to be efficient are low;
- if the regulation is biased towards CAPEX (which tends to be the case under rate-of-return regulation), companies are likely to choose CAPEX solutions over OPEX ones, even if these have higher 'whole-life' costs. This is known as the Averch–Johnson effect and, in more recent literature, is often referred to as the 'CAPEX bias' (see below).[7]

[6] The literature on basic incentive regulation is well known. For an overview, see Joskow (2014).
[7] Averch and Johnson (1969).

The criticism that rate-of-return regulation and cost-of-service regulation have low incentives to improve efficiency triggered the development of alternative regulatory models to incentivise better performance and efficiency. For example, in 1983, Littlechild proposed ‘RPI-X regulation’ for the newly liberalised telecommunications industry in the UK.[8] This type of incentive regulation became popular and quickly spread to other industries and other parts of the world. In the USA, incentive regulation is often called ‘performance-based regulation’ (PBR).[9] The key idea of incentive regulation is to delink allowed revenues from underlying costs.[10]

Typically, at the start of a regulatory control period, the allowed revenues are determined in advance. If the firm then performs well—by lowering its costs more than the regulator initially anticipated, for example—it can retain an agreed share of the cost savings as additional profit. This provides an incentive to reduce costs. There is ample evidence that this effect is strong.[11]

While, historically, incentive regulation has been aimed at achieving greater cost efficiency, the recent debate is increasingly focused on achieving other aspects of performance, notably quality of service and innovation. This is where output-based regulation principles comes to the fore. Output-based regulation has been defined as:[12]

> a regulatory framework to connect goals, targets, and measures to utility performance, executive compensation, and investor returns

Put differently, output-based regulation (and the associated incentives) links revenues to defined outputs in a way that explicitly recognises their costs as well as their value to consumers. The resulting output-based incentives can be included alongside other regulatory incentives that may be targeted at cost efficiency. In the USA, such incentives are often referred to as ‘targeted performance incentive mechanisms’ for specific tasks.[13]

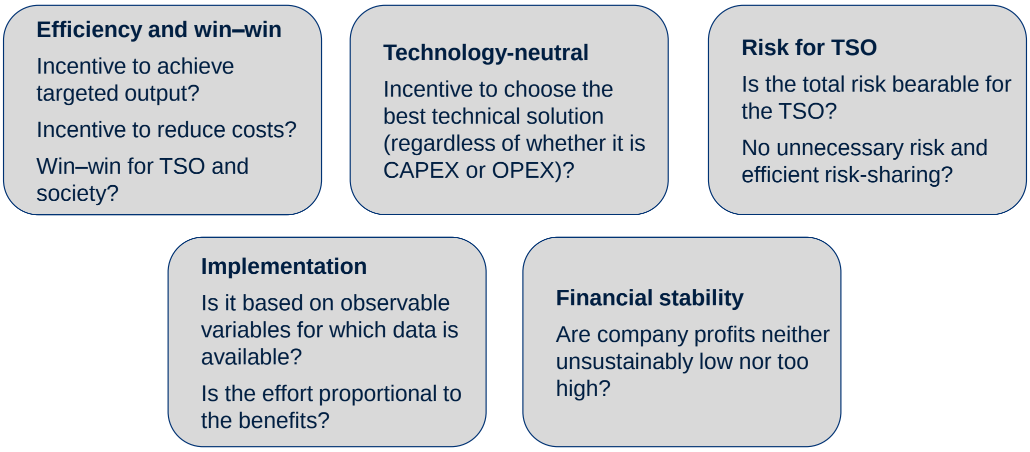
An example of this is the RIIO model (Revenue = Incentives + Innovation + Outputs) applied in Great Britain, which links regulatory revenues to six output categories set in the context of revenue cap regulation: safe network services, environmental impact, customer satisfaction, social obligations, connections, reliability and availability.[14]

3.2 Evaluation criteria for regulatory systems

Figure 3.2 summarises the broad criteria to evaluate the proposals for the adjustments of the regulatory systems applied in this report.

[8] Littlechild (1983).
[9] National Renewable Energy Laboratory (2017).
[10] Shleifer (1985).
[11] Sappington and Weisman (2010).
[12] National Renewable Energy Laboratory (2017), p. ix.
[13] Ibid.
[14] Ofgem (2010).

Figure 3.2 Criteria for a regulatory system



Source: Oxera.

Efficiency and win–win

The ‘efficiency and win–win’ criterion considers, first, whether the mechanism sets effective incentives to achieve the target output. Cost reduction, and thus productive efficiency, is an important criterion. In this report, other outputs considered are market facilitation, data facilitation and environmental protection. Second, it considers whether the incentives between the company and society are aligned—are the targets beneficial for the company *as well as* for society at large?

Technology-neutral

The criterion ‘technology-neutral’ reflects the objective of mitigating the risk of possible CAPEX bias. Incentive mechanisms should therefore be neutral between technologies, and in particular between CAPEX and OPEX when meeting users’ demand for infrastructure services. Regulation should therefore strive for appropriately balanced incentives for OPEX-intensive activities. The mechanisms should set an incentive to choose least-cost network development and operating solutions over the long term.

Risk for the TSO

There is a trade-off between the power of incentives and risk. For instance, profit-sharing (or bonus-malus) mechanisms reflect this trade-off well. This criterion requires that the risk for the company associated with incentive mechanisms should be balanced relative to the power and impact of the incentive. To mitigate risks, incentive mechanisms can be adjusted using uncertainty mechanisms, such as flexibility options and re-openers, or simply by capping the risks.

Implementation

The ‘implementation’ criterion considers whether the effort to implement the incentive mechanism is in proportion to the benefits of the mechanism. This applies to the legislator, regulator and the company. First, the implementation costs for the company should be in proportion to the benefits. Moreover, the requirement of reasonable implementation costs implies that the changes of the legal and regulatory system are moderate. Lastly, the mechanisms should be enforceable—in particular, parameters and metrics should be defined such that they are unambiguous, observable, controllable and not easy to manipulate.

Financial stability

Comparative stability of the profits of a regulated company brings some advantages. Losses and high profits can both create risk, which means there are two sides to this argument. If a regulated company makes losses, this could lead to unwelcome disruptions in service. While financial stability should not give carte blanche for wasteful or otherwise bad management, if the regulatory system allows for very high outperformance and hence profits, the regulator, despite being independent, might come under pressure from the public. This pressure could then lead to an increase in regulatory risk, because the regulator might feel pressured to renege on regulatory commitments previously agreed with the companies.

3.3 The literature: recent developments

This section highlights issues of particular relevance to the future role of TSOs and their regulation; namely, CAPEX bias, total value and output-based regulation.

3.3.1 CAPEX bias

As set out in section 3.1, one of the concerns often raised with some regulatory systems is that they unintentionally create an incentive to favour CAPEX over OPEX. This is important for two reasons.

First, a CAPEX bias may result in opportunities to reduce the overall costs being lost—for example, where it may be possible to defer CAPEX through demand-side measures. This risk is particularly acute in cases where the regulator is unable to internalise the complex trade-offs between infrastructure costs, user preferences, and impacts on service quality. Second, given the rapid development of new technologies for managing network demands and capacity availability, the opportunity cost of any CAPEX bias is likely to grow in future.

While regulators frequently debate the CAPEX incentive bias, it has received more limited attention in the recent academic literature, and the issue remains controversial. For example, regulators in Australia, Germany, the UK, and the USA have investigated potential policy responses to the CAPEX bias.

In the academic literature, this phenomenon has been emphasised as leading to ‘gold plating’ (i.e. excessive investment) in network capacity—in particular, where the allowed rate of return is higher than a utility’s actual cost of capital.[15] However, the empirical evidence for widespread gold-plating has been questioned by some authors.[16] Finally, in recognition of the potential that regulatory incentives provide a bias towards excessive CAPEX, it has been proposed that utility regulation be targeted at the provision of a return on TOTEX. In essence, this approach aims to treat both OPEX and CAPEX symmetrically, thereby reducing the risk of any CAPEX bias.[17] The recent application of a fixed CAPEX/OPEX *ratio* to TOTEX is intended to achieve the same effect, by capitalising a pre-specified proportion of TOTEX irrespective of whether it is OPEX or CAPEX.

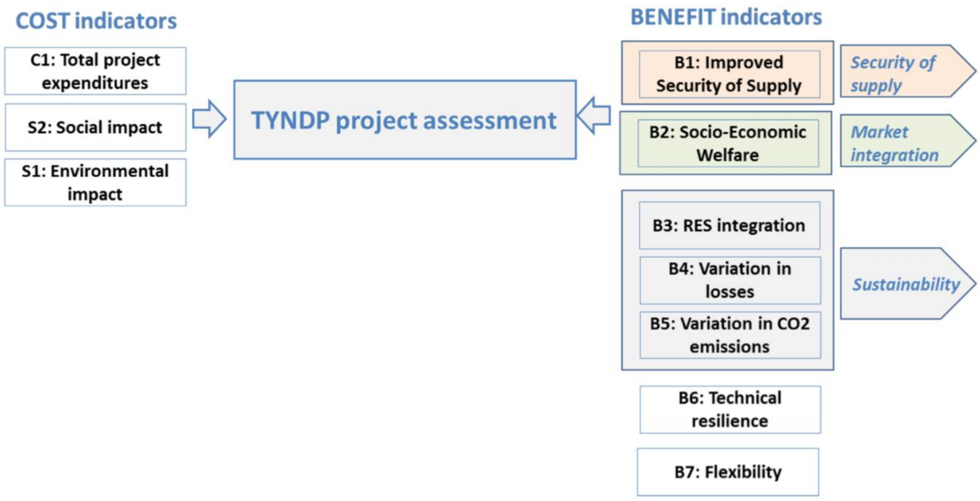
[15] Averch and Johnson (1969).
[16] Bormann and Finsinger (1999).
[17] Finsinger and Kraft (1984).

3.3.2 Total value

The concept of 'true value' or 'total value' (cf. True Price et al., 2014) shifts the focus from financial goals only to a broader set of goals, which include effects on the environment, the market and society at large.

We see the same principles applied in the social cost–benefit analysis (CBA) for transmission expansion. ACER (2016) developed guidelines for a unified CBA method for transmission investment, and gives the following overview.

Figure 3.3 CBA approach to transmission projects, as developed by ACER



Source: ACER (2016), figure 3.2.

Next to the usual engineering and economic objectives, social welfare goals are also represented in this framework. This includes market integration, but also integration of renewables and avoided CO_2 emissions.

Given the potential for greater opportunities for digital control and integrated management of electricity networks together with new demand-side and generation resources, new business models may emerge from electricity network operators. In particular, the future business models of electricity networks could encompass market facilitation, the connection and integration of renewable and other flexible energy sources, as well as data management and analysis.

An example of this trend is 'Reforming the Energy Vision' (NY-REV) in New York State, the aim of which is to:[18]

> transform "passive" distribution network operators into "active" distribution service providers – which are market facilitators.

The implication is that if TSOs are given a wider set of tasks and objectives, they may create more value for society at large through similar activities. In particular, TSOs are likely to be well placed to facilitate the coordination generation, demand-side and network resources to achieve ongoing system-wide cost reductions. The question is then: are TSOs adequately incentivised to pick up these tasks and develop these fields effectively and efficiently?

[18] Mitchell (2016),

3.3.3 Output-based incentive mechanisms

Beyond the well-established regulatory frameworks of cost-plus and revenue cap incentive-based regulation, regulators may find it useful to strengthen incentives for pre-specified targets or outputs. In the USA, collectively these are called targeted 'performance incentive mechanisms' (PIMs), and are defined by the National Renewable Energy Laboratory (NREL, 2017) as:

> a component of a PBR that adopts specific performance metrics, targets, or incentives to affect desired utility performance that represents the priorities of the jurisdiction. PIMs can be specific performance metrics, targets, or incentives that lead to an increment or decrement of revenues or earnings around an authorized rate of return to strengthen performance in target areas that represent the priorities of the jurisdiction.

Note that PBR and PIMs can be (partly) substitutes, but are normally complements. NREL presents the following 'specific design options'.

Figure 3.4 Specific design options for PIMs

1. No Explicit Incentive;
2. Shared Net Benefits;
3. Program Cost Adders and Target Bonuses;
4. Base Return on Equity (ROE) + Performance Incentive Payments to Reach Maximum ROE Cap;
5. Bonus ROE for Capital;
6. Base Incentives on kWh Targets;
7. Peak Reduction Targets;
8. Penetration Measures for DERs (including electrical vehicles);
9. Evaluation and Verification;
10. Every Employee with a PBR Goal, Target and Metric.

Note: DER, distributed energy resources.

Source: NREL (2017), p. 48.

NREL also provides a long list of PBRs/PIMs in operation in the US electricity utility industry, many of which may relate to non-network utility activities. A few that are or may be of interest to the network operator are:

- incentives for DER implementation;
- renewable energy performance metrics;
- operational incentives: improved interconnection request response times;
- operational metrics: incentives to improve reliability;
- incentives to support competition.

Overall, there is a trend towards developing roles beyond network services provision, in a narrow sense, towards creating value for society at large. To guide and promote these developments, regulation would ideally establish incentives to achieve targeted outputs. While the PIMs described above are examples from the USA, similar or alternative examples exist elsewhere, as we see in the next section. Beyond the USA, the same mechanisms are not necessarily called PIMs, but they are all output-based incentive mechanisms.

4 Regulatory practice

In addition to the brief review of the academic literature in section 3, Oxera has examined incentives and other features of regulatory systems found in other countries, some of which seek to tackle the same issues that this study is aiming to address. Together with the above literature review, this forms a useful starting point for developing concrete regulatory prototypes.

4.1 Which regulatory elements are used?

There are many different regulatory elements found in different jurisdictions. For this exercise, elements have been examined from the electricity network regulatory frameworks in Australia, Belgium, France, Italy, Portugal, the UK and the USA. For some countries, our research has focused on specific issues rather than all aspects of the regulations. As such, the summary below is not intended to be exhaustive.

The regulatory elements found in international regulatory systems for electricity have been examined according to the five criteria developed in section 3:

- efficiency and win–win;
- technology-neutral;
- risk for the TSO;
- implementation;
- financial stability.

Table 4.1 below gives a high-level overview of the regulatory elements considered, grouped by TSO function and the issue that they aim to tackle. While most regulatory systems include incentives for TSOs to plan, build and maintain assets efficiently, many fewer incentives can be found for other TSO roles. In particular, market facilitation, mitigating the environmental impact and data facilitation are rarely incentivised in existing regulation, although TSOs are expected to carry out these roles.

Table 4.1 Summary of regulatory elements

Area	Issue	Regulatory element
Assets	Efficient building and running of network, solving CAPEX/OPEX bias	**Fixed capitalisation rate**. A fixed proportion of TOTEX is capitalised, regardless of whether it is CAPEX or OPEX. As such, CAPEX and OPEX are treated the same, incentivising TSOs to adopt the most efficient solution. The regulator sets the fixed proportion to be capitalised
	Efficient network size: once the regulator has approved an asset (where applicable), there is no incentive for cost saving, or to defer or not build	**Incentive to capitalise saved CAPEX**. TSOs keep a share of the saved CAPEX that was planned to be spent but is not actually spent due to cost savings or because an investment was avoided by other means
	Additional risk from large investment projects, particularly over long regulatory periods	**Separate treatment of large investments**. This allows cost assessments within regulatory periods or for targeted network expansion
	Skewed incentives for timing of savings based on year or regulatory period	**Rolling incentive scheme**. This allows companies to benefit from cost savings for a fixed number of years, regardless of when in the regulatory period the savings have been achieved
	The lifetime of the assets can be longer than their depreciation period, but there is no incentive to maintain them once written off	**End-of-life incentive**. To incentivise maintenance and continued use of assets that are useful even after full depreciation, additional remuneration is paid for these assets so they are still part of the regulatory asset base (RAB)
	If there are incentives only for cost savings, network quality might suffer	**Quality regulation**. Output-based schemes can be used to incentivise quality, such as network reliability and safety. For example, an incentive on limiting outages can be based on the value of lost load
SO	If SO costs are mainly passed through, there is no incentive for the TSOs to save costs	**SO sharing factor**. The incentive is to save SO costs as the TSOs keep a share of any cost savings achieved. This could be asymmetric (only rewards are shared) or symmetric (rewards are shared or penalties are levied)
	Risk from high sharing factor due to non-controllable variability of SO costs	**SO risk/reward trade-off**. In addition to an SO sharing factor, there is a risk that TSOs are subject to a model that can be updated ex post to take into account exogenous/uncontrollable factors (e.g. weather) and/or caps and collars to limit risks and rewards
Market facilitation	No incentives on market facilitation in most jurisdictions, even though value is created	**Remuneration for value created**. To incentivise market facilitation, this scheme remunerates TSOs based on the welfare created for society—for example, from providing interconnector capacity. The welfare created could be estimated using existing CBA for interconnectors (e.g. from ENTSO-E) or by comparing modelling results with and without the interconnector capacity
Environmental	Beneficial to society to reduce CO_2 and SF6	**Environmental incentives** include output-based incentives to reduce the carbon footprint and SF6 leakage compared with a baseline level
Data facilitation	Not clear whether a data provider would need to be a fully regulated business—ring-fencing	**Regulation for asset-light data company**. A company providing data infrastructure is subject to different regulation for this asset-light activity (allowed to earn a margin on costs after regulatory scrutiny). TSOs might also provide data infrastructure, in which case this activity might need to be separated from the fully regulated TSO business
Overall	Incentives need to be aligned with what customers value	**Customer satisfaction incentive**. Financial incentive based on customer satisfaction determined via a survey. The financial impact of any rewards or penalties is limited to a proportion of revenue
	Investment in R&D to develop more efficient technology	**Innovation fund**. TSOs compete for an R&D budget and have to show progress of any funded projects

Note: [1] There is no specific method for setting the capitalisation rate. To avoid significant changes when this regulation is introduced, the rate might be set to approximate the proportion of CAPEX. For example, in the UK the capitalisation rate for SO costs is much lower than for other costs, reflecting that this is an OPEX-heavy activity. When this regulatory element was introduced in the UK, companies were invited to propose a fixed capitalisation rate. Source: Oxera based on review of international regulatory systems.

4.2 Lessons from review of regulatory practice

As set out in section 3, regulatory systems can be based on a cost-plus approach, a revenue or price cap (incentive regulation), or output-based regulation. A general trend found in electricity regulation across the countries examined is that they have moved away from cost-plus to incentive-based regulation, and, more recently, to a more market- or output-based regulation in some areas. For example, the USA has adopted PBR, which is a broader form of incentive regulation. In Great Britain, the RIIO framework is based around incentives, and includes a wide range of output measures with financial or reputational incentives attached. Italy is currently developing a system with some features similar to RIIO. Electricity regulation in Portugal also incorporates incentive-based elements. Similarly, Australia's scheme contains incentives for efficient CAPEX and OPEX spending, as well as financial penalties and rewards, calibrated according to consumers' willingness to pay for improved service. France, Belgium and Italy all have an incentive on cross- or within-border capacity that is based on the welfare generated from this capacity.

While there are examples of regulatory elements addressing other TSO roles, the majority of existing regulation concerns the planning, building and maintenance of assets. Some output-based measures have been implemented to incentivise market facilitation, environmental protection and data facilitation, but to date these are fairly small in scale.

5 Prototyping an improved regulatory system

In this section we bring together the future TSO roles, regulatory theory and the lessons from the review of regulatory elements. Using these three sources, we have derived two alternative prototypes for regulatory systems.

5.1 Overview

The prototypes are summarised in Figure 5.1 below. All of the TSO tasks are associated with a regulatory element that more closely aligns the incentives of the TSOs with the aims of society.

We suggest that regulatory incentives cover the following areas:

- TSO tasks associated with inputs should be regulated with elements that are based on the revenue cap principle;
- TSO tasks associated with outputs should be regulated with elements using output-based regulation.

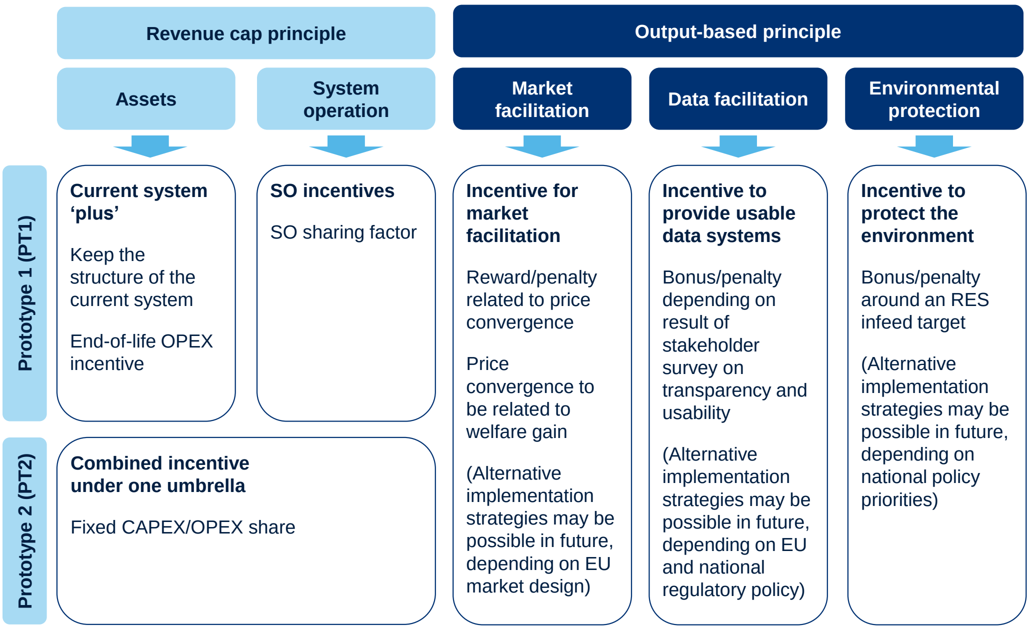
Both prototypes are improvements on the current regulatory system, rather than a complete overhaul of it. Furthermore, we suggest combining the two prototypes with the same set of financial output incentives.

An improved balancing of costs and benefits between the inputs and outputs can be achieved by the following measures.

- In Prototype 1 (PT1), the incentive to save costs (or the cost pass-through rate or incentive rate—see below) in the area assets and in the area SO should be calibrated to be more or less equal. This means that the regulatory parameters must be set such that the incentive to control costs in the area of assets is as strong as in the area of SO.
- In Prototype 2 (PT2), assets and SO costs are regulated under the same regulatory formula (a combined umbrella), which balances the incentives on both cost categories.
- The financial incentive to create certain outputs that TSOs are tasked with should be commensurate with the amount of value (consumer welfare) that these outputs create.[19] This would give the TSO an incentive to produce a welfare-optimal amount of each output.

[19] If that value is hard to measure, approximate measures may need to be used.

Figure 5.1 Overview of suggested regulatory prototypes



Source: Oxera.

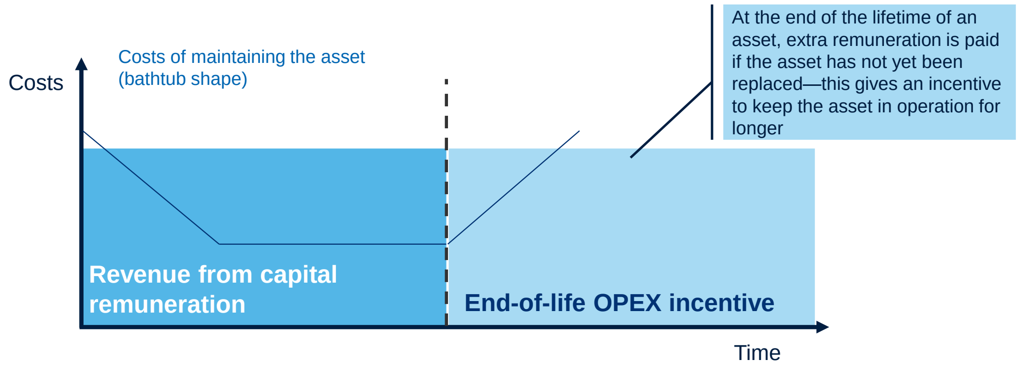
5.2 End-of-life OPEX incentive

Under the current regulation, TSOs may have an incentive to replace assets as soon as they are written off, in order to receive capital remuneration. This might be earlier than the end of their useful life. The end-of-life incentive therefore provides remuneration for assets for an additional number of years.

The logic is illustrated in Figure 5.2 below. The operating costs of an asset over its operational life usually follow a ‘bathtub’ shape. At the start, the costs are relatively high due to the early period of higher fault rates and other operational issues associated with the installation and early ‘run-in’ period for electro-mechanical systems. Operating costs are comparatively low thereafter, before rising again towards the end of an asset’s operational life due to increased wear and tear. The end-of-life incentive covers these upkeep costs such that the asset can stay in place for longer. Once the upkeep costs of the assets reach the allowance, the regulated company is likely to replace the asset. The extent to which this incentive leads to a more efficient replacement decision would depend on how it is calibrated. If the incentive is set too low, it may have no effect; if too high, it might entice the company to run an inefficiently high risk of failure.[20]

[20] To mitigate the risk of failure, this end-of-live incentive scheme could be accompanied by an incentive scheme for reliability goals, which would be an additional output incentive.

Figure 5.2 End-of-life incentive



Source: Oxera.

Using the five criteria developed, the end-of-life incentive can be assessed as follows.

- **Efficiency and win–win**: the incentive can be set such that the saved costs from reinvesting later are shared between the TSO and consumers. If the incentive is calibrated correctly, the reinvestment decision can be improved. The effect would be that network tariffs are lower than they would have been otherwise, provided that the more efficient CAPEX decision is not offset by the increased OPEX allowance. However, the incentive may increase the net present value (NPV) of newly made investments because companies know that they could get extra revenues from the end-of-life incentive. If a regulatory system already has a bias towards capital-intensive solutions, the end-of-life incentive could aggravate this bias. Whether this bias arises depends on whether the TSO believes that such an incentive would actually still be in place at the end of the lifetime of the asset.

- **Technology-neutral**: as noted above, the reinvestment decision might be improved because the distortion that comes from the fact that a new asset attracts allowed capital costs is corrected.

- **Risk**: leaving assets in place for longer might increase operational risk, which the regulated company will most likely bear. However, larger operational problems (outages) that also harm consumers are unlikely if the scheme is calibrated correctly. (As noted above, additional quality regulation can help with this aspect as well.)

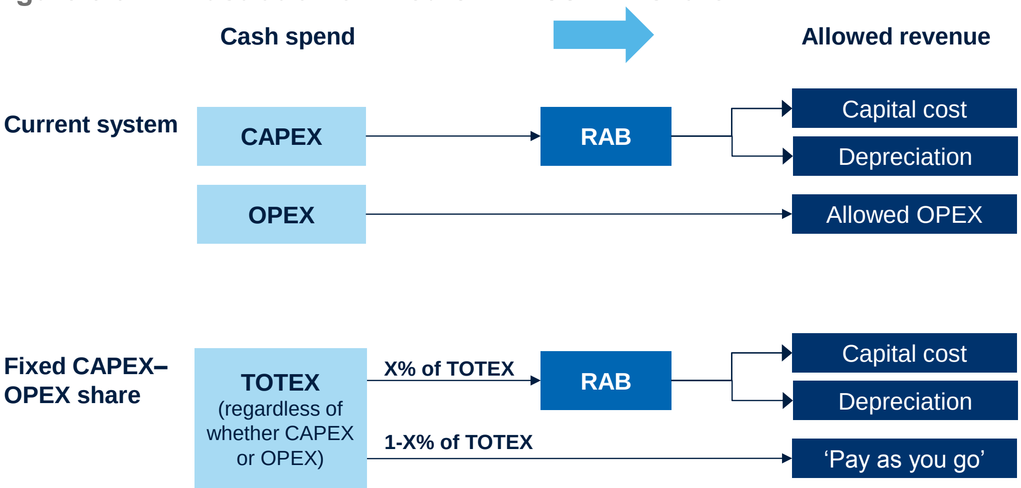
- **Financial stability**: the end-of-life incentive will introduce an additional OPEX allowance for assets that remain in use after their intended operating life. Since that additional OPEX allowance has the character of an annual lump sum, the TSO might be able to outperform the OPEX allowance if the expected incremental maintenance allowance is lower than the allowance itself. As described in section 3.2, this could lead to a perception that the incentive is unsustainable.

- **Implementation**: the implementation challenges mainly lie in the correct calibration of the allowance for differing types of asset. If the allowance is too low, it has no effect; if it is too high, TSOs might be induced to leave assets in operation for too long. Implementing this incentive means that the regulator would have to build up knowledge on asset monitoring and asset lives in order to be able to calibrate the incentive correctly. Going forward, such allowances would have to be revised periodically as more information on actual asset performance becomes available.

5.3 Fixed CAPEX/OPEX share

The fixed CAPEX/OPEX share aims to treat all costs the same in terms of activation (capitalisation through the RAB) and expensing, irrespective of whether they are OPEX, CAPEX or SO costs.[21] In doing so, any bias towards CAPEX that may come from CAPEX creating a return on capital would be eliminated. Regulated companies would be free to choose the best technical solution, be it OPEX- or CAPEX-based (see Figure 5.3).

Figure 5.3 Illustration of fixed CAPEX/OPEX share



Note: 'Pay as you go' refers to costs that are recovered every year or during the control period, and therefore are treated similarly to OPEX in the current system.

Source: Oxera.

In the current regulatory system, CAPEX is capitalised and creates allowed capital costs and depreciation that are added to allowed revenues. OPEX is expensed directly.[22]

Under the new system of the fixed CAPEX–OPEX share, all costs would be regarded as TOTEX. That would include costs for investments, maintenance and SO, and for the procurement of flexibility. A fixed share of these costs would then be added to the RAB creating allowed capital costs and depreciation that are added to the allowed revenue. The balance of the costs would be expensed directly.

These new rules would mean that a certain fixed percentage of cash spent on actual capital goods would be added to the RAB. Equally, a similar fixed percentage of cash spent on OPEX—for example, on flexibility measures or other smart solutions—would also be added to the RAB. In doing so, and thereby treating all costs the same, a fixed CAPEX/OPEX share would make sure that the technology decision of the TSO is not biased by differing treatments of CAPEX or OPEX. Similarly, it would remove any need for the regulator to check whether certain costs are OPEX or CAPEX.

In principle, to equalise the incentive between TOTEX and CAPEX, any fixed capitalisation rate could be used.

Using the five criteria developed, the fixed CAPEX–OPEX share can be assessed as follows.

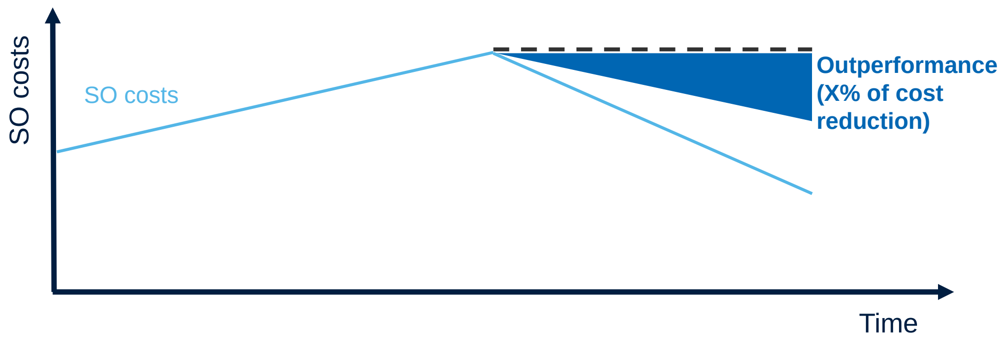
[21] Alternatively, it is possible to treat only CAPEX and OPEX under the new regime, and to treat SO costs under a separate incentive scheme, such as that described in section 5.4.
[22] This is abstracting from efficiency assumptions that regulators would be likely to impose.

- **Efficiency and win–win**: by removing any potential bias towards CAPEX-heavy solutions, the potential of OPEX-based solutions can be unlocked (assuming that such efficiency opportunities exist). The issue around the efficient replacement of assets is also resolved. This is because OPEX spent on increasing maintenance costs would be treated similarly to the CAPEX replacing it.
- **Technology-neutral**: technological neutrality is being 'hard-wired' into the system.
- **Risk**: depending on the capitalisation factor, the company may face an increased need for additional financing because it may have to fund capitalised OPEX.
- **Financial stability**: at some point in the long term, a large proportion of the RAB may stem from capitalised OPEX, leading to a divergence between the regulatory and statutory accounting statements for the TSO, particularly as regards the regulator's value of the RAB compared to the accounting value of fixed assets.
- **Implementation**: at the time of implementation of this measure, it may be desirable to maintain a legacy RAB alongside a separate RAB for assets recognised using the fixed CAPEX/OPEX ratio. Assets that are in the RAB already could simply remain there and be depreciated as originally planned. New additions to the RAB could then be treated according to the new rule. Similarly, the capitalisation rate would have to be set, and, in practice, it would most likely be close to the current CAPEX/OPEX share so as to avoid larger tariff variations over time. Furthermore, the precise rules and parameters of such a new scheme would have to be further specified.

5.4 SO incentives

For PT1, an outperformance incentive for SO costs could be included (as illustrated in Figure 5.4). In each year, the SO costs of the year before form the benchmark. Any out- or underperformance relative to the benchmark is shared between the company and customers. Thereby, the blue wedge in Figure 5.4 represents the sharing factor. While the blue part of the cost reduction goes to the TSO, the white part of the cost reduction is passed directly on to customers. The precise amount of the sharing factor can be set in a regulatory consultation. If the sharing factor is higher, the company will have a stronger incentive to control SO costs, but also expose the TSO to more risk.

Figure 5.4 Incentive to reduce SO costs



Source: Oxera.

Using the five criteria developed, the SO sharing factor can be assessed as follows.

- **Efficiency and win–win**: an incentive is created to control SO costs, and any gains and losses are shared. This means that TSOs as well as customers can profit from the scheme.
- **Technology-neutral**: applying the scheme to all SO cost categories means that the TSO has an incentive to optimise between SO costs and asset costs. As such, it would reduce any pre-existing bias between network solutions that are CAPEX-intensive and network solutions that involve significant SO costs.
- **Risk**: SO costs can be volatile and may be highly dependent on non-controllable factors, so the risk exposure of the regulated company may be significant. In addition, this would not necessarily be an efficient sharing of risk since the company would be exposed to risk that it cannot control.

  Instead of simply using the SO costs of the last year as benchmark costs, the benchmark could be set by a model ex post that accounts for non-controllable factors. Such an approach would take out the non-controllable risk, while still giving an incentive to control costs and an opportunity to outperform.
- **Financial stability**: this incentive could lead to significant over- and underperformance against the SO cost target, although this could be mitigated by using an incentive formulation.
- **Implementation**: a benchmark based on the SO costs of the previous year is comparatively straightforward to implement, depending on the availability of information on the amount of balancing and redespatch services that are procured, and at what price. A more complex formulation of this incentive scheme could be used that controls for uncontrollable SO cost drivers such as market trends and weather conditions.

Constructing a model that yields ‘fair’ benchmark costs, and removes the effect of non-controllable variables such as weather and wholesale market prices, is conceptually not difficult. In practice, however, it would be a sizeable modelling exercise. Nevertheless, given the importance of SO costs and the amount of unnecessary risk that can be removed by such a modelling exercise, it may well be worthwhile. Alternatively, the risk exposure of the TSO can be lessened by reducing the sharing factor, although this would be at the expense of the incentive power of the scheme.

5.5 Incentive for market facilitation

As noted in section 2.1.3, TSOs play a role in facilitating the market-based exchange of electricity, by:

- making cross-border capacities available to international electricity trade (geographical dimension);
- providing in future (at least partly) the necessary data infrastructure needed for flexibility markets (depth dimension).

5.5.1 General approach

How can a TSO be incentivised to exert an optimal amount of effort in order to facilitate markets?

An input-based approach would be hard to implement because it would be difficult for a regulator to understand precisely what inputs are needed to achieve an optimal market outcome. Equally, an exogenously determined interconnection capacity target has weaknesses too. If, for example, an arbitrary X% of additional interconnection capacity is set as a target value, it is hard to know whether this X% is good for overall welfare. It may be that the TSO could have achieved much more than X%, or that providing the X% is actually very costly, and possibly even more costly for end consumers than the benefits of additional cross-border trades enabled by the X%?

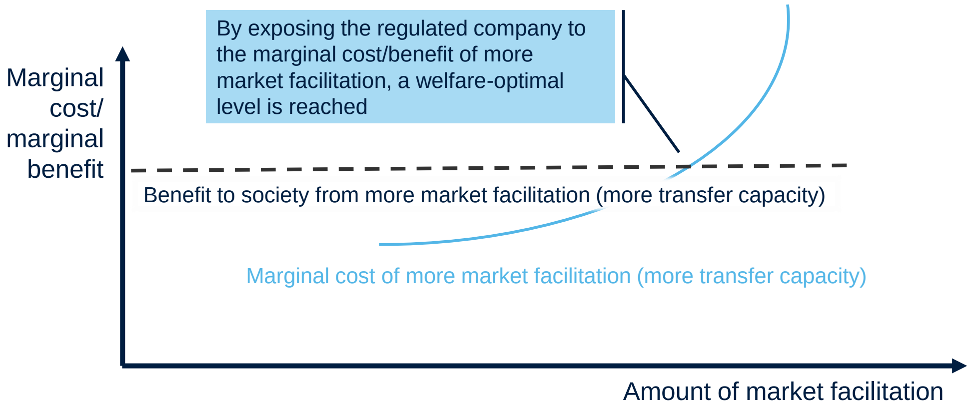
However, the way in which the provision of goods and services would work in a well-functioning market gives some guidance on how an incentive mechanism for market facilitation should ideally look. In a well-functioning market, the price that companies receive for a good is equal to the benefit that the good creates for the marginal customer. If the production costs of that good are higher than the benefit it creates for the marginal customer (expressed by the customer's willingness to pay), the good is not produced. Goods that can be produced at a cost that is lower than the benefit they deliver are produced.

The same principle can be applied in regulation. If the additional incentive that a regulated firm receives for an additional unit of a certain output is equal to the additional benefit that unit creates for network clients, the regulated firm will produce the welfare-optimal amount of that good.

This 'carrot' approach has the additional advantage that the regulator does not have to worry about how the regulated company achieves the output.

The principle is illustrated in Figure 5.5 below. As long as an additional unit of market facilitation (such as transfer capacity) can be created at a cost that is lower than the benefit, the additional unit would be produced. This increase in transfer capacity would be repeated until the benefit of an additional unit of transfer capacity is equal to the cost of an additional unit of transfer capacity. Because the carrot that the company is rewarded with is oriented towards the welfare gain, a welfare-optimal amount will be produced.

Figure 5.5 Principle of output-based regulation



Note: For simplicity, we assume here that the benefit curve is flat (horizontal).

Source: Oxera.

5.5.2 Incentivising an optimal amount of cross-border capacity

This section suggests a possible approach to operationalise the principle of output-based regulation set out above for a market facilitation incentive. Market facilitation enables gains from trade, leading to price convergence and overall welfare gains.

Figure 5.6 considers an approach for incentivising cross-border capacity. This is based on price convergence because prices are observable. Price convergence also represents a possible indicator of welfare gains that materialise because of market facilitation.

The amount of price convergence achieved can be measured using a price convergence index. This can be linked to welfare gain with a factor that quantifies the welfare gain that each index-point change in price convergence would cause.

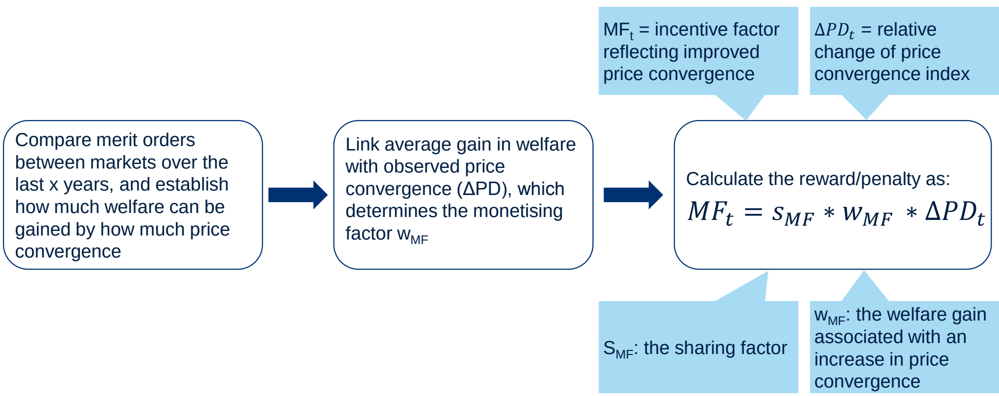
Figure 5.6 illustrates how a welfare factor could be estimated. We suggest a stepwise approach:

Step 1 The merit-order curves in the respective markets are investigated and compared. From this comparison, an estimation of how much welfare is created by price changes in the markets is derived.

Step 2 These welfare changes are linked to changes in a price convergence index (PD). The result is the monetising factor (W_{MF}).

Step 3 The annual reward/penalty is calculated. For the calculation, a sharing factor between 0% and 100% is chosen (see section 5.4). If from one year to another, price convergence improves, this will lead to additional outperformance from the scheme, and vice versa if it deteriorates. In any case, the amount is added to/subtracted from the allowed revenues formula.

Figure 5.6 Process for incentivising cross-border capacity



Source: Oxera.

Using the five criteria developed, the market facilitation incentive can be assessed as follows.

- **Efficiency and win–win**: an incentive is provided to achieve the welfare-optimal amount of cross-border capacity. Potential welfare gains are shared between the regulated company and customers.
- **Technology-neutral**: only the output is incentivised, and the mechanism is agnostic in terms of how the TSO reaches the goal. As such, the mechanism is technology-neutral. In other words: if there are ways to

improve market integration that are not based on CAPEX, this incentive would make sure they are developed and used.[23]

- **Risk**: price convergence is potentially volatile and, as with SO costs, may be partially non-controllable. As with SO costs, this could be addressed by modelling that accounts for non-controllable factors.
- **Financial stability**: as with the SO cost incentive, this mechanism could lead to significant over- and underperformance against the price convergence target, although this could be mitigated by using alternative incentive formulations.
- **Implementation**: while price convergence is observable, a possible correction of the benchmark level of price convergence for non-controllable factors is complex. Ideally, such a scheme would be implemented at an EU level in order to capture all the interdependencies that arise because TSOs in one country will have an effect on price convergence in other countries.

5.5.3 Incentivising flexibility markets

Going forward, when locational flexibility services markets emerge, TSOs will play an important role in providing data on the basis of which such markets will work. To incentivise TSOs to foster these markets as well as they can, the TSOs could receive a share of the marginal welfare gains created by these markets.

5.6 Incentive to provide data infrastructure and transparency

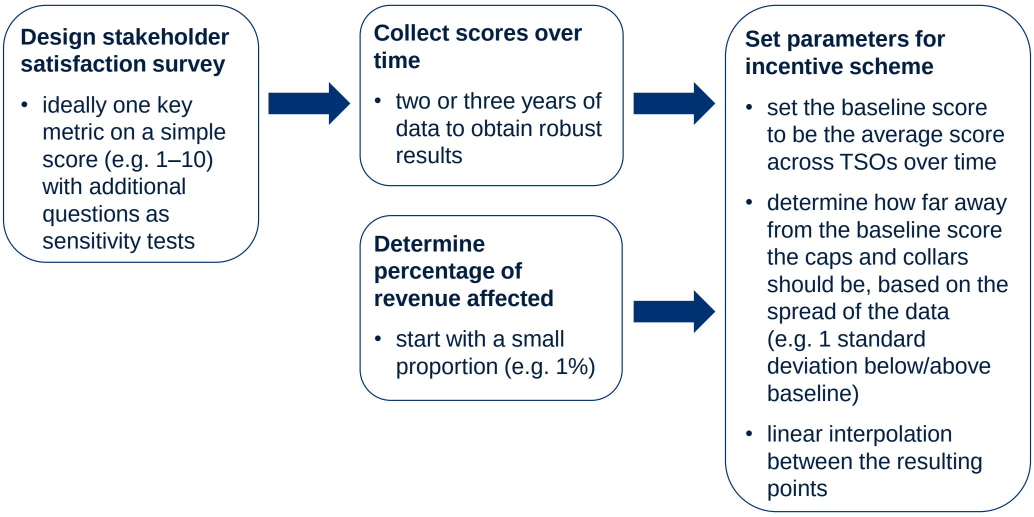
As described in section 2.2, one key future role for the TSOs is to provide a data infrastructure that can generate welfare by enabling value-added services. For example, a new business model might be based on using close-to-real-time market information on network congestion in order to enable smart demand-side responses. These types of service would require the TSOs to provide a data infrastructure that is transparent to, and usable by, such third parties. However, at present, there is no financial incentive for the TSOs to improve their data facilitation role.

One way of directly incentivising the role of a data facilitator could be to design an incentive based on the revenues generated through these new markets. However, due to the significant uncertainty around what these markets might look like in future, including how large they are likely to be, this report proposes an output-based incentive based on a stakeholder survey methodology, as used in the UK. This was summarised in Table 4.1 above.

The premise is that users/stakeholders are best placed to judge the practicality of data provided by the TSOs. Therefore, there could be a financial incentive contingent on the outcome of a stakeholder survey. In contrast to a more prescriptive input-based approach (which might require data standards that are not actually beneficial to the data user), this proposed approach incentivises TSOs to cooperate with users in order to provide a data platform that can generate value. The process of designing such an incentive is shown in Figure 5.7.

[23] At this point, the 'information revelation' aspect of incentive schemes becomes clear. The amount of market integration that can be achieved is private information of the TSO. By introducing such a scheme, the regulator could get more information on what is technically feasible.

Figure 5.7 Data facilitation incentive



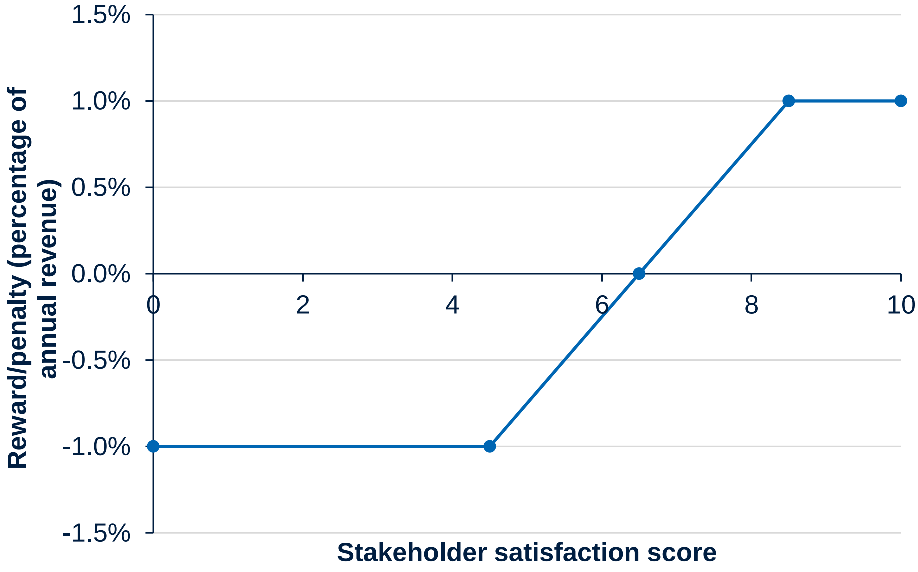
Source: Oxera.

The stakeholder survey would need to be carefully designed and provide a metric (e.g. a score from 1 to 10) to represent how usable and transparent a TSO's data is. Using results over a period of time, from several TSOs where applicable, the survey scores would have to be calibrated to establish:

- a baseline score (which could simply be the average score of TSOs over the period for which data is available);
- the points at which the maximum reward/penalty would be incurred. This would depend on the spread of the data. For example, if all scores are very close to the average then the maximum reward might already be applicable at a score that is only slightly higher than the average.

Once the incentive is introduced, TSOs achieving the baseline score would not be rewarded or penalised. A TSO scoring better/worse would receive/pay a certain proportion of its revenue subject to a cap and collar, which would limit the financial impact of this incentive. An illustrative relationship between the scores achieved and the resulting penalty/reward, which in this example is limited to ±1% of revenue, is shown in Figure 5.8 below.

Figure 5.8 Illustrative example of converting survey scores to a financial incentive



Source: Oxera.

The baseline score in this example is 6.5; therefore, a TSO scoring 6.5 would not receive any payments. The maximum financial reward is earned when scoring 8.5 or higher. To obtain the corresponding financial impact for any scores in between, a linear interpolation is used between the points (6.5/0) and (8.5/1%). The incentive can be symmetric, with penalties for scoring below the baseline score mirroring rewards from scoring above it.

Using the five criteria developed, the data facilitation incentive can be assessed as follows.

- **Efficiency and win–win**: assuming that data transparency leads to welfare gains, this incentive results in a win–win situation for TSOs and society. It is one way of ensuring that the TSOs cooperate effectively with data users.
- **Technology-neutral**: this is an output-based incentive and therefore technology-neutral. TSOs can adopt whatever approach they wish and are evaluated only according to the quality and transparency of data provided.
- **Risk**: the incentive is based on the results of surveys, which inherently contain some degree of subjectivity. However, the financial impact of the incentive is limited by the percentage of revenue affected.
- **Financial stability**: there are limited risks associated with the data facilitation process. Clear rules would need to be established to decide who is eligible to participate in the stakeholder survey. In addition, TSOs and data users need to comply with data protection rules.
- **Implementation**: while the survey needs to be well designed, overall this incentive is fairly straightforward to implement. Some historical data needs to be collected first in order to calibrate the incentive function.

The implementation of such a scheme would also have to consider the extent of regulatory ring-fencing. Data functions that belong to the role of a TSO as an infrastructure provider should be regulated, and fair access to all data for all market participants should be provided. However, some data functions may not belong to the infrastructure role of a TSO and should therefore be provided on market-based terms.

5.7 Incentive to protect the environment

Below, we concentrate on the incentive for TSOs to take up RES infeed. Accommodating greater amounts of renewable generation is arguably the most significant environmental task for TSOs. A future regulatory system does not need to be restricted to RES infeed, however. For example, incentives to reduce ‘bads’ such as land use, SF6[24] emissions or other environmental impacts are all feasible.

Currently, the obligation (and exceptions to it) to absorb RES infeed in the Germany and the Netherlands are governed by legislation. As outlined in section 5.5.1, exogenous and inflexible rules are not well suited to providing incentives to balance costs and benefits optimally.

So, how could TSOs be correctly incentivised for RES infeed?

With RES production already being subsidised, the goal of this scheme is not about incentivising further RES capacity. Rather, it is to give the TSO a correct incentive, or ‘price signal’, when it comes to deciding how much renewable energy should be absorbed and how much should be curtailed.

Given that a TSO may be forced, at a certain time, to trade off additional RES infeed against network capacity being made available to other users (e.g. cross-border capacity), this could significantly increase SO costs or require further investment in physical capacity. Therefore, to incentivise a more efficient trade-off in view of the prevailing constraints, it would potentially be beneficial for a mechanism to equalise the additional benefit that the TSO could receive for each additional 1MWh of RES to the value of that unit of generation. Under PT1 and PT2, SO costs would already be fully incentivise; therefore any compensation that the TSO pays for curtailment will already be factored in. This implies that, under PT1 and PT2, some of the lost value of curtailed electricity will already have been ‘priced’ in the TSO’s incentives.

Any value over and above the compensation paid that RES electricity has for society as a whole—for example, the value of saved CO_2—can form the basis for this scheme. When implementing such a scheme, for example, the incentive could be calculated by multiplying the implied value of avoided CO_2 (per MWh) by the change in yearly renewable curtailment.

Using the five criteria developed, the environmental incentive can be assessed as follows.

- **Efficiency and win–win**: if balanced correctly, this incentive, together with the other incentives, could lead to the TSO correctly optimising the trade-off between asset costs, system costs and the outputs market facilitation, data facilitation and environmental protection. This optimisation could lead to a reduction in overall costs, which could create outperformance from which TSOs can profit (win–win).
- **Technology-neutral**: the additional remuneration for RES infeed is agnostic in terms of how that is achieved. As such, the scheme is technology-neutral.

[24] A powerful greenhouse gas used in transmission equipment.

- **Risk**: the growth of RES infeed may be partially outside the control of the TSO.
- **Financial stability**: the switch from a legal obligation (with exceptions to absorb RES infeed) to a correct 'pricing' of RES infeed might lead to changes in the amount of infeed curtailed. Such changes might trigger discussions on whether outperformance payments resulting from this are justified.
- **Implementation**: RES infeed and curtailment are observable and are already being recorded. A 'value' of RES infeed in welfare terms would also need to be determined.

6 Impact assessment

Oxera has conducted indicative modelling to quantify the impact of the suggested reforms on:

- the incentives for TenneT to control costs;
- TenneT Germany's revenues, costs and outperformance;
- welfare changes arising from these reforms, particularly the cost savings.

In this section, we describe the modelling approach (section 6.1), before calculating the marginal incentive to spend or save funds in certain cost categories under a stylised version of the German/Dutch system and under PT1 and PT2. From these incentive margins, we derive assumptions about how different cost categories for TenneT will develop under the different regulatory systems (section 6.3). Lastly, we present the results for costs, welfare and outperformance under the current system, PT1 and PT2 (section 6.4), based on a version of the model that has been calibrated using data from TenneT Germany.

6.1 Modelling approach

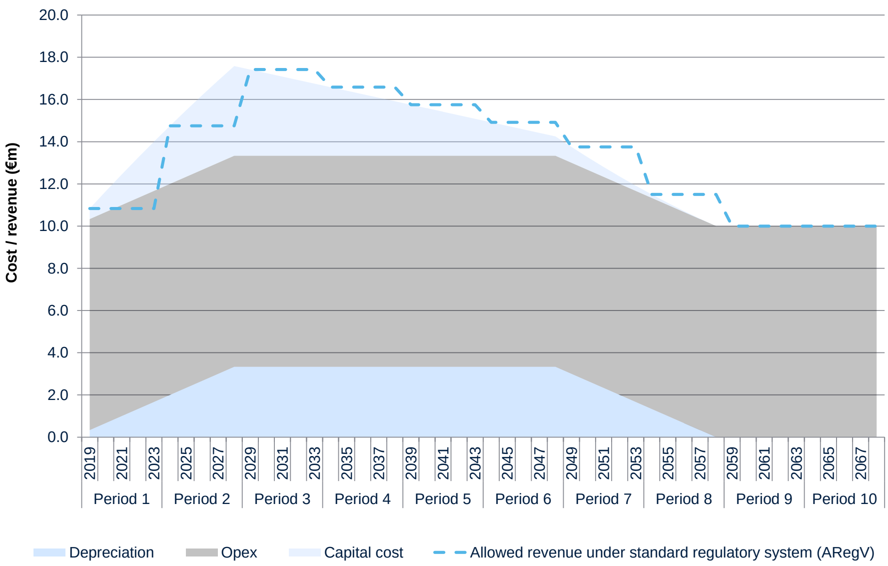
6.1.1 The model

Figure 6.1 below shows the basic structure of our regulatory model. We start with assuming a certain amount of OPEX and CAPEX under a 'business as usual' scenario. These investments enter the RAB and generate allowed depreciation and allowed capital costs.

The basic regulatory system is a five-year revenue cap. Allowed revenues are based on costs in the first year and delinked from actual costs for the next four years. Allowed revenues are then re-set for the next control period.

In the example shown in Figure 6.1, investments are undertaken until the end of control period 2. In other words, it is assumed that the current investment wave will continue until 2030. Thereafter, the RAB is depreciated over an assumed lifetime of 30 years. The modelling horizon is 50 years (ten regulatory periods). A discount rate or allowed return of 5% is assumed throughout.

Figure 6.1 Model of incentive regulation—costs, allowed revenue and outperformance



Source: Oxera.

To model the changed incentive systems, PT1 and PT2, the way in which costs are transformed into allowed revenues has been changed accordingly.

- In PT1, assets receive additional revenue equal to depreciation and capital costs of 20% of the original RAB for four years (end-of-life incentive).
- In PT2, CAPEX and OPEX are considered to be the same cost category. Of this, 90% is added to the RAB (capitalised), where it is written off over an assumed asset life of 30 years. Regardless of whether the costs are CAPEX or OPEX, 10% are 'pay as you go' (i.e. expensed annually) and hence are added directly to current costs. SO costs are considered to be TOTEX as well, but the capitalisation rate for these is 10%.[25]

Step 1: Modelling the incentives of the current system, PT1 and PT2

To understand the incentive properties of the alternative regulatory systems, we use the following approach.

- We assume a cost reduction of €1 in OPEX, CAPEX and SO costs.
- The effect of such a change is then calculated under the standard system, and under PT1 and PT2. It is also calculated for the first and last year of the regulatory period.
- The effect of the cost reduction on the NPV of outperformance is calculated.
- If the resulting change in NPV is greater than 1, the regulated company creates more value when it reduces its costs, and less value when it increases its costs. We call this the incentive rate, or the cost pass-through rate. It can be interpreted as follows: if the incentive rate is, say, 3.38, a reduction in costs by €1 would increase the NPV of outperformance by €3.38.

[25] The capitalisation rate for asset costs and SO costs has been set at different levels because the actual share of CAPEX to OPEX is different in the respective areas.

Step 2: Assuming rates of cost change

Positive incentive rates mean that the company creates more outperformance (earns more money) when costs are reduced—the higher the incentive rate, the higher that effect. Costs that are treated as a pass-through item have an incentive rate of zero—i.e. there is no incentive at all to control costs.

We assume that over time a stronger incentive for reducing costs will lead to more cost-reducing innovations by the TSO. While the magnitude of innovation that incentives will trigger can be difficult to forecast, we assume that stronger incentives will lead to greater results.

Step 3: Calculating outperformance and welfare change

The assumptions derived in step 2 are then fed back into the three regulatory models: the current system or business as usual case, PT 1 and PT2. We obtain estimates for the NPV of welfare increases and company outperformance over the 50-year period of our model.

In what follows, we define welfare improvements as reductions in OPEX, CAPEX and SO costs relative to a scenario in which all costs stay the same.[26] Increases in the value of outputs will increase welfare.[27]

6.2 Calculation of incentive rates

Table A1.1 in the Appendix shows the resulting incentive rates, which we elaborate on below.

Current regulatory system in Germany and the Netherlands

- The current system results in stronger incentives to control OPEX than CAPEX. As shown by the difference in incentive rates between the year after the base year and the base year of the regulatory period, there is a strong incentive for costs to be incurred in the base year (and for cost reductions to be made in the year after the base year).
- Reserve costs are incentivised, but the calibration of the regulatory mechanism is not made public. An incentive rate equal to the discounted sharing factor is therefore used.
- Redespatch costs are treated as pass-through, so there is no incentive to control these.
- There are no output-based incentives. Market facilitation, data facilitation and RES infeed are regulated by legislation or not incentivised at all.

The proposed changes to the incentive scheme are intended to address the limitations of this regulatory system.

- There are incentives to control OPEX. However, because of the five-year revenue cap principle, the fact that the same five-year revenue cap is applied to CAPEX means that there is less of an incentive to control CAPEX. The allowed return earned on CAPEX leads to the CAPEX bias distortion.

[26] This definition assumes that the lower cost can be achieved without negative repercussions on service quality.
[27] This assumes that the societal 'value' placed on the outputs is approximated by the monetary values referred to in sections 5.5 to 5.7, such as the price of carbon in the case of emission reductions.

- There are no incentives to control balancing costs, which are specifically applied to reserve costs.
- Redespatch costs are not incentivised.

Prototype 1

- While the incentive rate for OPEX is the same as in the standard regulatory system, the incentive rate for CAPEX is assumed to be lower. This is because every investment in CAPEX triggers some extra return at the end of its lifetime, which increases the NPV of CAPEX. This is the case only for new investments. For reinvestments, the end-of-life incentive has a balancing effect (it should nudge the reinvestment decision towards an ideal and later point in time).
- The assumption of a cost-sharing factor of 50% implies an incentive rate of 0.475. This means that a reduction of SO costs by €1 now triggers additional earnings of €0.5 in a year from now, the NPV of which is 0.475. Therefore, there is an incentive to control SO costs.
- As set out in section 5.5.1, incentives to provide relevant outputs are proposed in the PT1 and PT2 models.

Prototype 2

- Under PT2, all costs are treated similarly, irrespective of whether they are CAPEX, OPEX or SO costs. Therefore, the incentive to control these costs is symmetric, and the incentive rates for these costs are assumed to be the same.

6.3 Modelling assumptions

In what follows, we derive assumptions about the evolution of costs under the current regime and under PT1 and PT2. These cost-saving parameters are assumptions-driven. Predicting the precise amount of innovation that incentives will lead to is difficult; nevertheless, we proceed under the following two broad assumptions.

- **Incentives are effective**: in general, incentives will focus the attention of management. As such, cost-reduction incentives are expected to result in lower costs over time, even if the precise amount of these reductions is difficult to forecast. When there are incentives to control costs and these lead to outperformance opportunities for the company, the interests of consumers and companies are aligned.
- **Balanced incentives create more opportunities for optimisation**: balanced incentives mean that the regulatory regime does not distort the technology choice of the regulated company. The more such distortions are absent (e.g. the more balanced the incentives are), the better the result can be. This is because the firm is free to choose the best technical solution.

The cost-saving assumptions presented here are drivers of the results presented in section 6.4. The fact that the welfare gain is larger in PT1 than in the current regime, and larger in PT2 than in PT1, is driven by our assumption that more aligned and more balanced incentives will lead to higher cost savings.

Table 6.1 shows the cost-saving assumptions that are used.

Table 6.1 Assumed cost savings based on incentive rates

	Incentive regulation		
	Assets		SO
	OPEX	CAPEX	
Current system	-1% p.a.	-0% p.a.	-0% p.a.
Prototype 1	-0.5% p.a.	-0.5% p.a. investment wave delayed by four years	-0.5% p.a.
Prototype 2	-1% p.a.	-1% p.a.	-1% p.a.

Source: Oxera.

The rationale behind the cost-saving assumptions is as follows.

- When modelling the current regime, we assume that OPEX will decrease by 1% p.a. and all other cost items will remain constant. This is because the current system does create incentives to control OPEX. The assumption behind this is that if there is an incentive to control certain costs, this will take the form of cost savings. In the current system, there are no strong incentives to control costs in other areas, which is why we assume that there are no cost changes in the other cost categories.
- For PT1, we assume that CAPEX decreases by 0.5% p.a. relative to the base case, which is set by the investment trajectory of the current system. Behind this is the assumption that a reduced incentive for replacement expenditure reduces total replacement expenditure and, with it, CAPEX. We also assume that reinvestments are delayed by four years because of the incentive to delay CAPEX. Since the delay in CAPEX will trigger additional maintenance costs, we assume a reduction in OPEX of only 0.5% p.a.

  With SO costs incentivised under PT1, we assume a reduction of 0.5% p.a. as well.
- For PT2, we assume that the balanced incentives unlock further opportunities for optimisation between cost categories (see above). Therefore we assume a cost reduction across the board of 1% p.a.

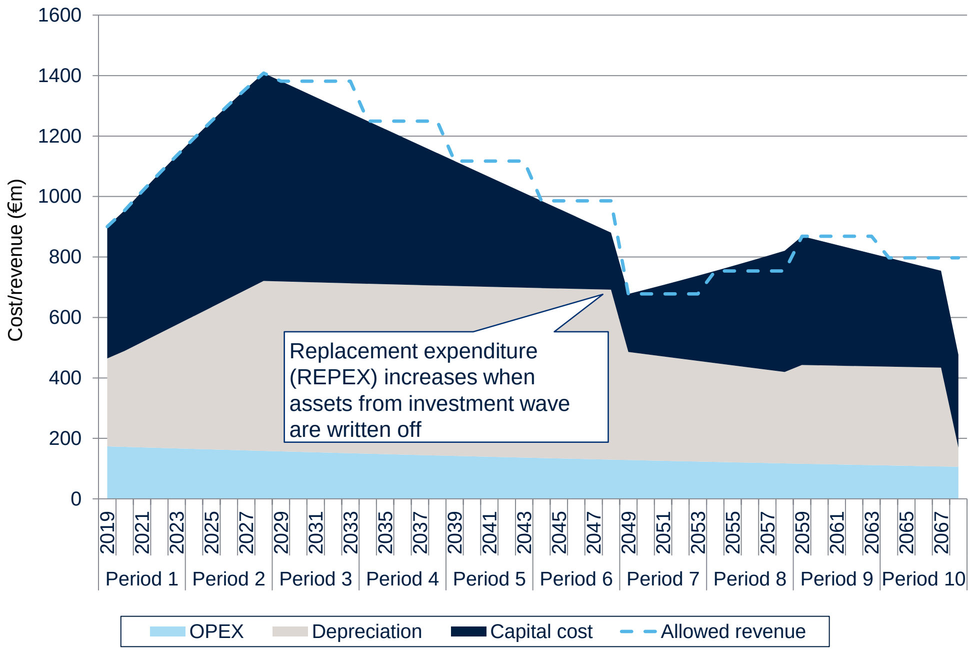
6.4 Results—impact on outperformance and consumer welfare

Below, we present the results of the indicative quantification. Figure 6.2 gives a forecast of costs calibrated with data provided by TenneT Germany.

- The first 'investment wave' will lead to increasing revenues until 2028, after which revenue will decline. After 2049, only replacement investments takes place.
- OPEX is decreasing slightly over time, creating some outperformance throughout the five-year revenue cap mechanism.
- Depreciation and capital costs are increasing while the investment wave is ongoing, and then decreasing as the existing capital stock is depreciated. The drop in the late 2040s is because a large part of the current asset base leaves the RAB at that point in time. Modelled reinvestments lead to an increase in depreciation and capital costs again after 2049.
- The allowed revenue tracks costs closely as they increase during the first two regulatory periods. This reflects the effect of regulatory

'investment measures'. The plateau effect creates outperformance as allowed costs decrease. Rising costs due to reinvestments create a negative plateau effect after 2049. In general, outperformance can be seen to be driven more strongly by the plateau effect and less by actual cost savings.

Figure 6.2 Costs, allowed revenue and outperformance under current model



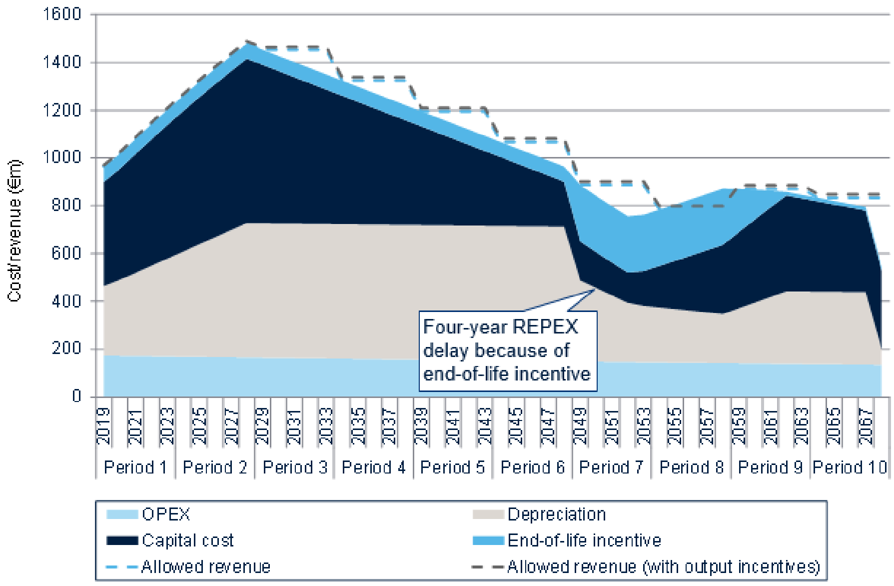
Note: Cost forecasts have been calibrated with data from TenneT Germany. In the first ten years, the effect of the investment measures is modelled by updating allowed revenues according to costs annually, instead of only every five years.

Source: Oxera.

Figure 6.3 shows the cost, revenue and outperformance forecast for PT1. It can be seen that, particularly when the investments of the first investment wave are being written off (between about 2049 and 2060), significant additional revenues are created by the end-of-life incentive.

In PT1, most costs have a pattern similar to that in the current model. A difference is the stronger decrease in depreciation and capital costs after 2049 because of delayed investment.

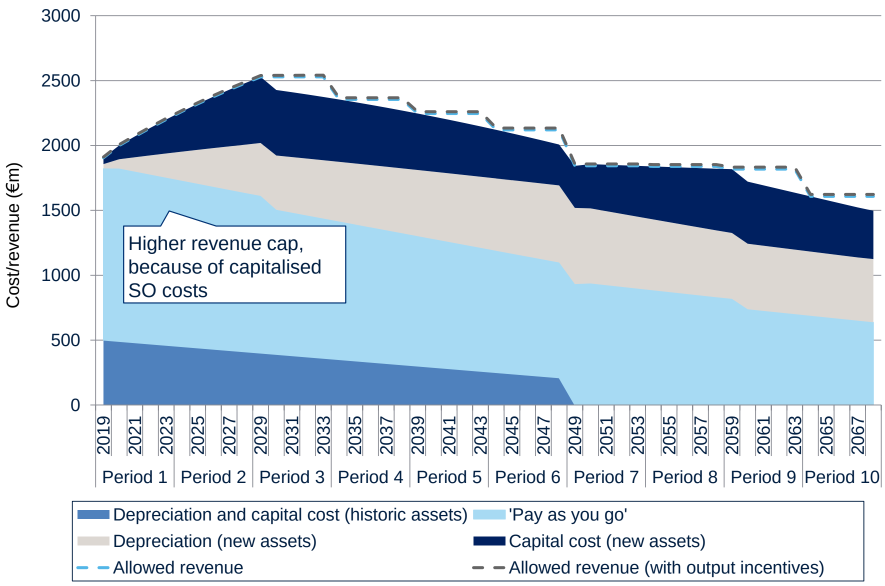
Figure 6.3 Costs, allowed revenue and outperformance under PT1



Source: Oxera.

Figure 6.4 shows the development of allowed regulatory costs and allowed revenues under PT2.

Figure 6.4 Costs, allowed revenue and outperformance under PT2



Source: Oxera.

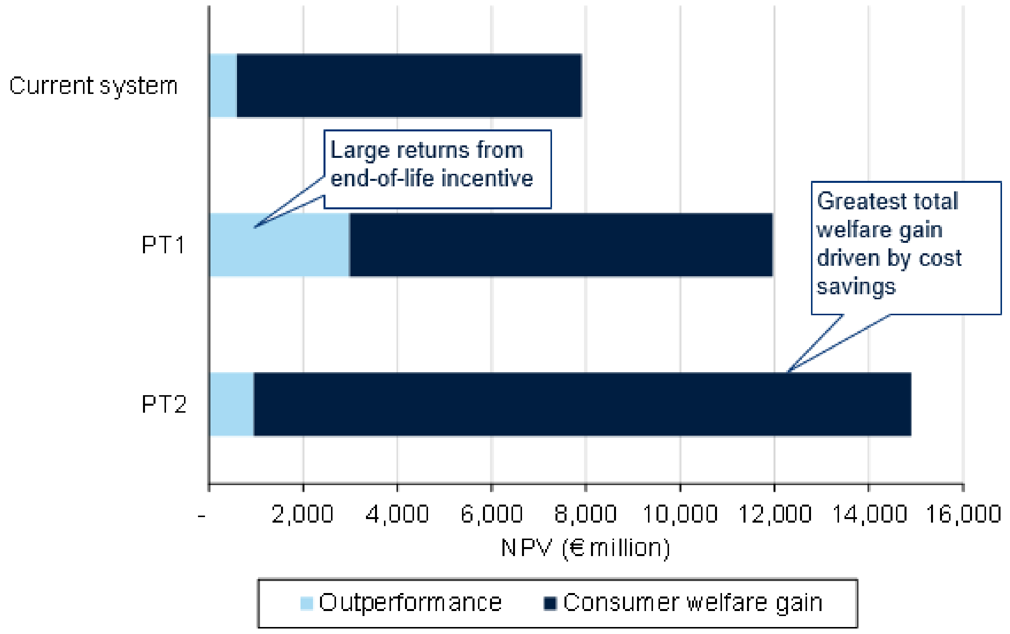
The following observations on Figure 6.4 can therefore be made.

- Oxera assumed that assets that are already in the RAB would simply be depreciated as originally planned. This seems a pragmatic assumption of how the transition from the current system to the system of a fixed CAPEX–OPEX share could be organised: depreciation and capital costs (historic assets).
- Because SO costs are now included under the revenue cap, the cap is significantly higher than before.

- The profile of allowed costs is different to that under the current system. There is less of a peak in capital remuneration during periods of high investments because part of the investments will be treated as pay-as-you-go. However, due to the capitalisation of OPEX, there is more capital remuneration in later years.
- Outperformance is still strongly influenced by the relative timing of cost peaks and base years. We have again assumed that investment measures will be applied for the first two regulatory periods. Because of this, allowed revenues track costs directly as they rise. The new capitalisation rules would lead to overall trajectories of allowed costs that are less steep. This has a limiting effect on the overall outperformance, even when we assume higher efficiency gains under PT2.

Figure 6.5 compares the NPV of welfare gains and company outperformance.

Figure 6.5 Welfare and outperformance under current system, PT1 and PT2



Source: Oxera.

The following observations on Figure 6.5 can be made.

- Welfare gains are driven by cost savings. PT2 results in higher welfare gains than PT1, which leads to higher welfare gains than the current system.
- Because cost savings also drive outperformance, PT2 results in more outperformance than the current system.
- PT1 stands out because of the larger outperformance, driven by the end-of-life incentive. As noted in section 5.2, this incentive mechanism introduces an additional OPEX allowance for assets that remain in use after their intended operating life. Given the challenges of calibrating this incentive, it is perhaps more likely that the incentive rate would be periodically revised, depending on the extent of the TSO’s financial outperformance. As a result, the actual outcome of applying PT1 may be less generous than shown in our modelling.

7 Conclusion

This report has considered alternative models for the regulation of TSOs in future. This has been motivated by the observation that, while the TSO's roles include asset management, SO and market facilitation, the current regulatory system focuses largely on asset remuneration, with limited incentives for TSOs to optimise between inputs and outputs. Furthermore, in future, the role of a TSO as a data facilitator and managing overall environmental impacts is likely to become more important.

To maximise social welfare, financial incentives should cover all the relevant tasks of a TSO and be appropriately targeted. This report has set out two suites of 'smart' incentives and quantified their impacts through illustrative modelling.

The aim of these regulatory reform proposals is to achieve a greater alignment of interests between TSOs, national regulatory authorities, and customers. especially as the reforms help to overcome any bias towards CAPEX-intensive solutions and provide stronger incentives to reduce TOTEX (including SO costs).

Increased emphasis on other TSO 'outputs' can also help to improve consumer welfare. For example, lowering system-wide costs through data and market facilitation, and improved environmental protection.

Notwithstanding the potential benefits of regulatory reform to both TenneT and its customers, practical implementation challenges remain to be addressed, and further detailed analysis of potential risks and returns is possible.

In order to operationalise all or some of the suggestions, the following next steps could be followed. The first step would involve making the incentives around the asset management task more concrete.

- The incentive properties of the end-of-life-incentive and the fixed CAPEX/OPEX share have been investigated at a high level in this report. In a next step, some more concrete examples of investment and technology choice could be used to test the incentives in more detail.
- Both the end-of-life-incentive and the fixed CAPEX/OPEX share can be broken down into concrete implementation steps. The relevant issues are timing, accounting rules, available technologies, and the impact on financial stability.

The second step would involve detailed design of an appropriate SO incentive.

- The risk properties of SO costs and their potential impact on the financial stability of TSOs under PT1 and PT2 would need to be understood in greater detail.
- If the volatility of SO costs is very high, some modelling that adjusts the benchmark SO costs for uncontrollable factors could be considered.
- Some of the SO costs are actual economic costs to customers, while a proportion are effectively transfers between market participants. The impacts of any reform to SO would therefore need to be considered in light of the incentives on a wider set of market participants (especially generators).

As the third step, based on the concept of output-based regulation, the following design parameters for incentivising market facilitation would need to be investigated further:

- alternative output variables such as price convergence or welfare created;
- a measure to ensure harmonisation and coordination between European TSOs;
- a definition of what is seen as controllable by TSOs in the scheme (execution of despatch, finding cheaper sources of redespatch), and what is seen as non-controllable (size and structure of bidding zones).

A fourth step would be to design an incentive for data facilitation:

- identifying the stakeholders and their requirements for data aggregation and analysis services;
- designing a robust survey methodology to track TSO performance in data facilitation;
- constructing a suitable customer satisfaction index.

The fifth, and final, step would be to design an incentive for RES infeed:

- check whether the relevant documentation in public databases is reliable enough to form a basis for regulatory incentives;
- investigate the value to society of an RES infeed.

A1 Incentive rates resulting from the current system, PT1 and PT2

Table A1.1 Incentive rates under current system, PT1 and PT2

		Incentive regulation			
		Assets		SO	
		OPEX	CAPEX	Reserve	Redespatch
Current system	Max. (in year after base year)	3.38	0.44	Incentive rate equal to sharing factor	Pass-through
	Min. (in base year)	0.00	0.35		
Prototype 1	Max. (in year after base year)	3.38	0.11	0.45	0.45
	Min. (in base year)	0.00	0.01		
Prototype 2	Max. (in year after base year)	1.91	1.91	1.91	1.91
	Min. (in base year)	0.17	0.17		

Source: Oxera.

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Smarter incentives for transmission system operators

Volume 2

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Contents

Figures and tables

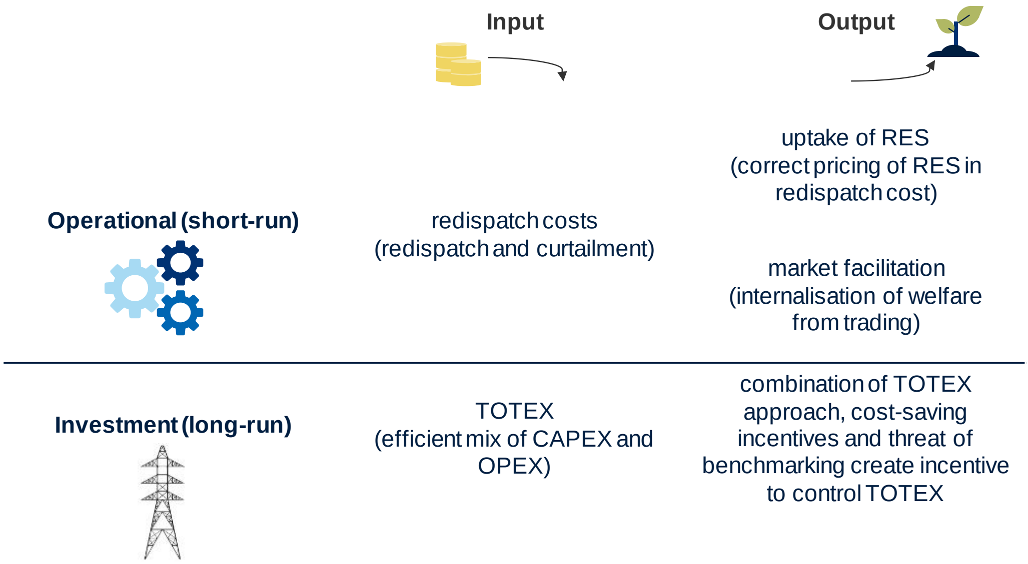
Executive summary

Increased renewable generation, decentralised generation and technological advances are changing the electricity system, bringing challenges and opportunities for transmission system operators (TSOs). As a result, their roles are evolving and becoming more complex. This in turn makes it increasingly important that TSOs, when managing their networks, have regulatory incentives to make the most efficient decisions from a socioeconomics/welfare perspective, to the benefit of society as a whole.[1]

On the operational side, a key challenge for TSOs is to avoid redispatch costs while encouraging increased renewables-infeed. In Germany, these aspects are not currently addressed within the existing regulatory regime, with costs treated as pass-through for the most part[2] and outputs achieved through fixed rules.[3]

On the investment side, there is a need to incentivise TSOs to choose the most efficient solutions, considering both investment (capital expenditure—CAPEX-based) and operational (operational expenditure—OPEX-based) measures where appropriate.

Inputs and outputs in the electricity system



Note: RES, renewable energy supply; TOTEX, total expenditure, CAPEX, capital expenditure, OPEX, operational expenditure.

Source: Oxera.

In light of these challenges, it is particularly important for a regulatory regime to allow TSOs to internalise trade-offs and to provide them with financial incentives that result in a service that is optimal for the system as a whole (i.e. that is welfare-optimal).

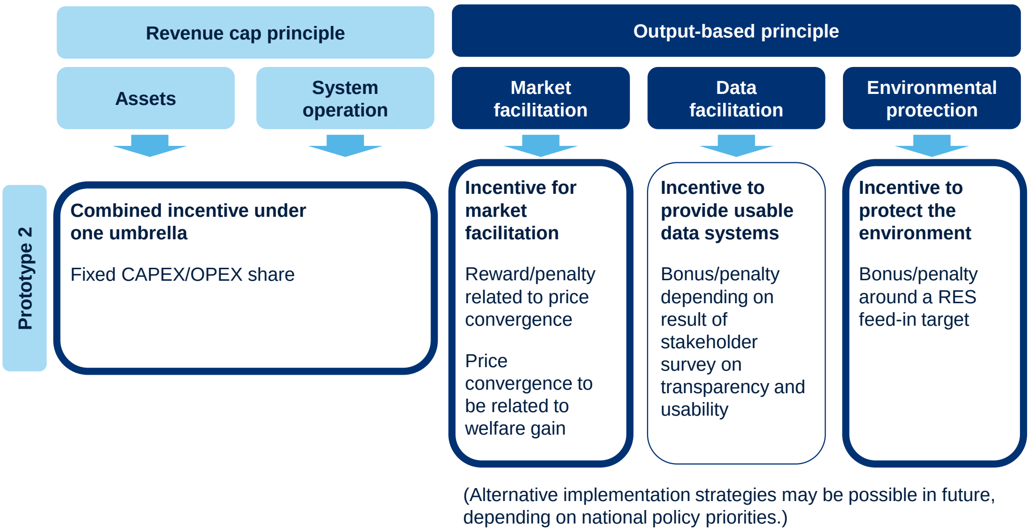
[1] Particularly in the setting of network regulation, maximising welfare often means reducing costs (which means a lower burden on consumers).
[2] In the Netherlands, there is a financial incentive to save redispatch costs, which is limited to 5% of the budget for redispatch costs, which in turn is based on past redispatch costs. See Autoriteit Consument & Markt (2016), 'Methodenbesluit Transporttaken TenneT 2017–2021', para. 10.1.
[3] Examples of fixed rules are the obligation always to absorb renewable production, and the rule that states that 70% of available net transfer capacity should be made available for cross-border electricity trade. See Regulation (EU) 2019/43 of the European Parliament and of the Council of 5 June 2019 on the internal market for electricity, Article 16(8).

Oxera's first study on smarter incentives for TSOs[4] examined how the regulatory system might evolve. For that study, we developed two high-level prototypes, both with a focus on:

- ensuring that incentives were balanced between investment and operational measures; and
- introducing incentives for issues that thus far have been regulated by legal rules, rather than economic incentives.

This study takes Prototype 2, the more ambitious of the two, and develops it further. As illustrated below, it combines the fixed CAPEX/OPEX share and output-based regulation, both of which are described in more detail below.

Results of the previous study—Prototype 2



Note: For this follow-up study, the elements in the boxes highlighted by the thicker borders have been developed further.

Source: Oxera based on Oxera (2018), 'Smarter Incentives for TSOs', July.

Output-based incentives

Output-based incentives are payments to a regulated firm based on the amount of a desired output that a TSO generates, rather than on its inputs (i.e. its costs). Such an output might be available transfer capacity or the accommodation of renewable infeed, for example. Two output-based incentive systems are presented in this study. These have evolved from the high-level ideas in Prototype 2, illustrated above. Market facilitation and environmental protection are both currently being regulated by legal rules, rather than economic incentives. As a result, they are unlikely to be economically efficient because these legal rules do not afford the TSOs the flexibility to optimise the provision of outputs against costs.

- **Market facilitation** (cross-border trade) creates welfare through the merit-order effect, as less costly generators in one market replace more costly ones in another market. This welfare impact can be calculated directly using bid curves compiled by electricity exchanges.

  The incentive scheme developed in this report relates the financial incentive for a TSO to provide capacity for cross-border trade to the welfare

[4] Oxera (2018), 'Smarter Incentives for TSOs', July.

generated from such trade. In every hour, the TSOs could then internalise the trade-off between costs associated with providing more capacity and the welfare generated from additional trade. The analysis conducted in this report suggests that the welfare that can be achieved from trade and the costs associated with market facilitation vary significantly between hours. This means that a fixed target, such as the EU-wide 70% target, which does not take into account the trade-offs in any particular hour, is unlikely to be welfare-optimal.[5]

- **Priority feed-in for renewables** (**RES-infeed**) could save CO_2 emissions that would have been emitted by conventional generation. At the same time, if there are constraints in the network, it could cause high redispatch costs. Our proposed output-based incentive approach would solve this by pricing RES curtailment in a way that captures the associated costs and CO_2 savings. This would allow the TSOs to internalise the trade-off between increased costs and decreased CO_2 emissions. As with market facilitation, the incentive would vary from hour to hour, depending on the constraints present in the network. Because it aligns the incentives of society with the incentives of the TSO, and because it gives the TSO the flexibility necessary to solve the trade-off between the costs of curtailment and the costs of redispatch, such a system would be more economically efficient than the current inflexible rule in Germany of priority dispatch for renewables.

Fixed OPEX/CAPEX share

In addition to output-based incentives, this study develops further the fixed OPEX/CAPEX share (FOCS) proposed in the first study. The aim of the FOCS is to design incentives for investment measures (CAPEX) and operational measures (OPEX) that are balanced (and hence unbiased), allowing the TSO to choose the most efficient solution overall. There are several reasons why a CAPEX bias might exist (i.e. because grid operators prefer a CAPEX solution to an equivalent OPEX one).

- Practical limitations to estimating the cost of equity mean that a regulator might err on the side of caution, given the large downside risk of underestimating it. There could be an OPEX disadvantage if:
  - OPEX has a higher likelihood of increasing during the regulatory period, for example if certain operational costs are more variable and more difficult to control than CAPEX. This can also happen when the allowed revenue for the regulatory period is based on historical costs that are not in line with expected future OPEX;
  - there is a perception of OPEX being more likely to be disallowed as part of the cost audit;[6]
  - there is a risk that OPEX will not be remunerated in full.

The FOCS system introduces greater technological neutrality into the regulatory system by treating all costs, whether they are CAPEX or OPEX, exactly the same. It does so by grouping together CAPEX and OPEX into TOTEX, and capitalising a fixed share of all these costs. In doing so, it

[5] Regulation (EU) 2019/43 of the European Parliament and of the Council of 5 June 2019 on the internal market for electricity, Article 16(8).
[6] This applies to the German framework only.

decouples differences in remuneration (regulatory asset base versus pay-as-you-go) from the types of activity (CAPEX versus OPEX).

Our analysis suggests that, under either a modelled positive CAPEX bias or negative OPEX bias, FOCS helps to align the incentives that the TSOs face for different types of solution. We then examine how FOCS fits into the current regulatory formula in Germany, and how it would interact with certain parts of the regulatory system, such as the efficiency benchmarking regime.

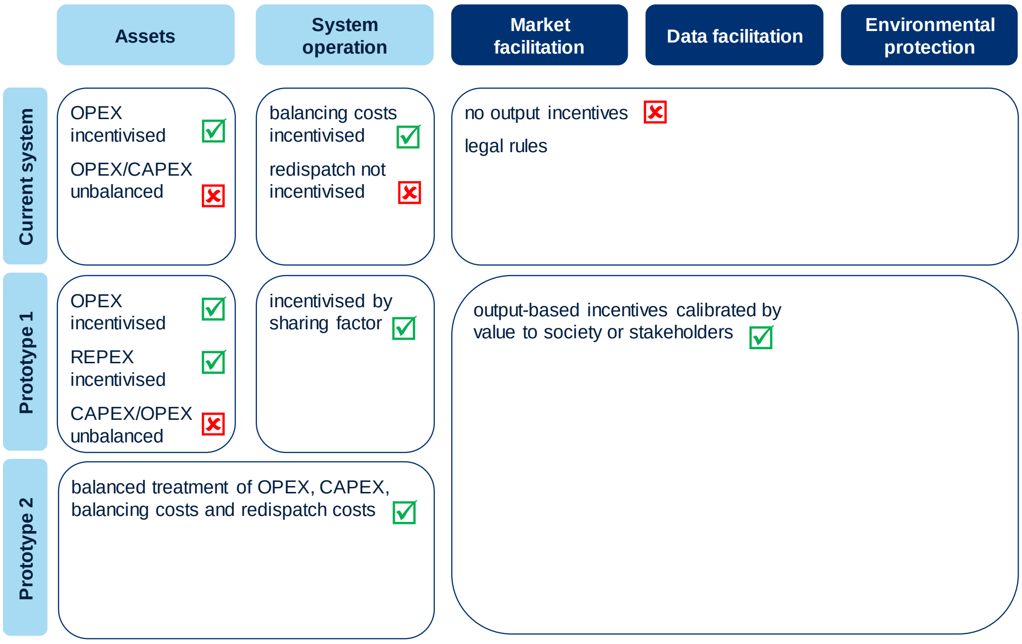
The proposals developed as part of this study are based on the premise that trade-offs should be aligned and internalised by the TSOs. The choices available to the TSOs with respect to trading off RES-infeed and redispatch costs, and CAPEX and OPEX, against each other should therefore not be distorted by rules and regulations. Rather, the TSOs should have both the flexibility and the incentive to opt for the most efficient solution overall. This would increase welfare for society, but would not necessarily mean that the TSOs would receive more remuneration under these proposals.

1 Introduction

The role of TSOs is changing as the energy system evolves. This means that TSOs are expected to carry out some new tasks, while others may become less important in the future.

In this context, it is important that the regulatory system covers these tasks appropriately so that the TSOs' incentives are aligned with the objective of maximising welfare.[7] A potential misalignment between tasks and incentives was explored in Oxera's earlier study for TenneT,[8] the high-level results of which are summarised in Figure 1.1.

Figure 1.1 Tasks and incentives under the current and proposed regulatory system



Note: Redispatch is not incentivised in the German system.

Source: Oxera.

A key finding from that study was that incentives between investment measures (CAPEX) and operational measures (OPEX) are unlikely to be balanced, which might create disincentives for operational solutions. Moreover, tasks such as RES-infeed and the provision of net transfer capacities are currently regulated by legal rules, rather than economic incentives.

Our proposed changes to the regulatory system aim to:

- balance the incentives between CAPEX and OPEX by introducing a fixed OPEX/CAPEX share (FOCS); and
- create incentives based on the welfare created for tasks carried out by the TSOs, such as market facilitation and environmental protection.

This report explores these elements in more detail:

[7] Particularly in the setting of network regulation, maximising welfare often means reducing costs (which means a lower burden on consumers).
[8] Oxera (2018), 'Smarter Incentives for TSOs', July.

- section 2 covers output-based incentives for market facilitation and RES-infeed;
- section 3 discusses the FOCS.

2 Output-based incentives

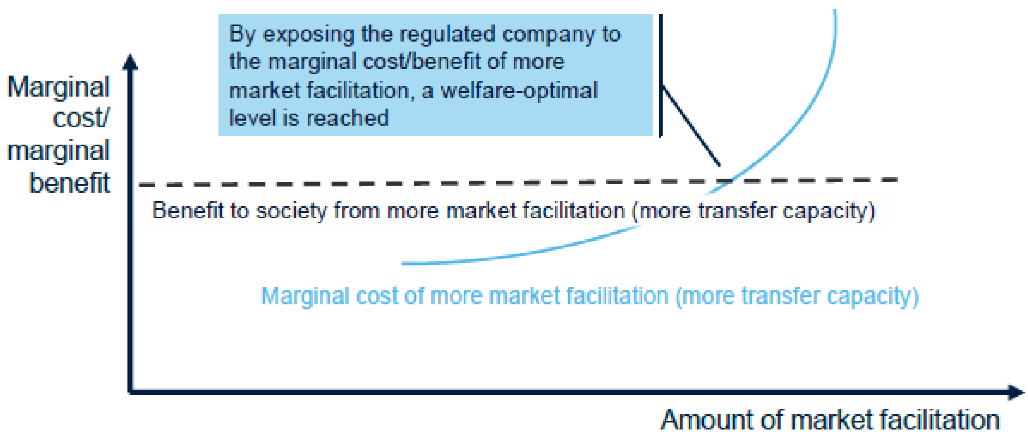
The TSOs are expected to perform certain tasks for which there are currently no economic incentives.[9] Fixed rules, such as the 70% of net transfer capacity (NTC) target for market facilitation[10] or priority feed-in for renewables (known as RES-infeed),[11] can be useful to ensure certain behaviours.

However, these rules may not be welfare-optimising for society at all times. This is because society does not necessarily value only a single output, and focusing on a single target ignores the associated trade-offs with costs and other outputs. For example, while market facilitation and the benefit from cross-border electricity trade are important, basing a target solely on this aspect ignores the fact that providing cross-border capacity is costly and takes away resources from other areas (e.g. it might have been possible to use the capacity for increased RES take-up). As an alternative, in this section we propose output-based incentives that enable the TSOs to **internalise such trade-offs** and align their incentives with the welfare of society.

The premise behind output-based incentives is illustrated in Figure 2.1. In this simple, stylised example, the marginal benefit to society of market facilitation is constant[12] (as depicted by the dashed line). The marginal cost is upward-sloping.

If the TSOs are rewarded according to the benefits they create and are exposed to their own costs of creating these benefits, the outcome will be a welfare-maximising amount of the incentivised output (in this case of market facilitation). In principle, this system does not require the regulator to know the costs that the TSOs face, provided that the welfare impact can be estimated. The strength of the incentive can then be calibrated by the welfare impact, and the company will adjust its effort/cost to the strength of the incentive, such that a welfare-optimal amount of output is reached.

Figure 2.1 Output-based incentive for market facilitation: illustrated example



Source: Oxera.

[9] Oxera (2018), 'Smarter Incentives for TSOs', July.
[10] Regulation (EU) 2019/43 of the European Parliament and of the Council of 5 June 2019 on the internal market for electricity, Article 16(8).
[11] Erneuerbare Energien Gesetz (EEG) 2017, para. 14.
[12] This is a simplifying assumption; in reality, the marginal benefit might be increasing up to a certain point and then decrease again.

The output-based incentives for market facilitation and RES-infeed proposed in this section are described in turn below.

2.1 Market facilitation incentive

One of the tasks undertaken by the TSOs, but which is not currently subject to an economic incentive, is market facilitation. Here, we refer to market facilitation as the actions that the TSOs can take to make cross-border capacities available and thereby facilitate cross-border trade.

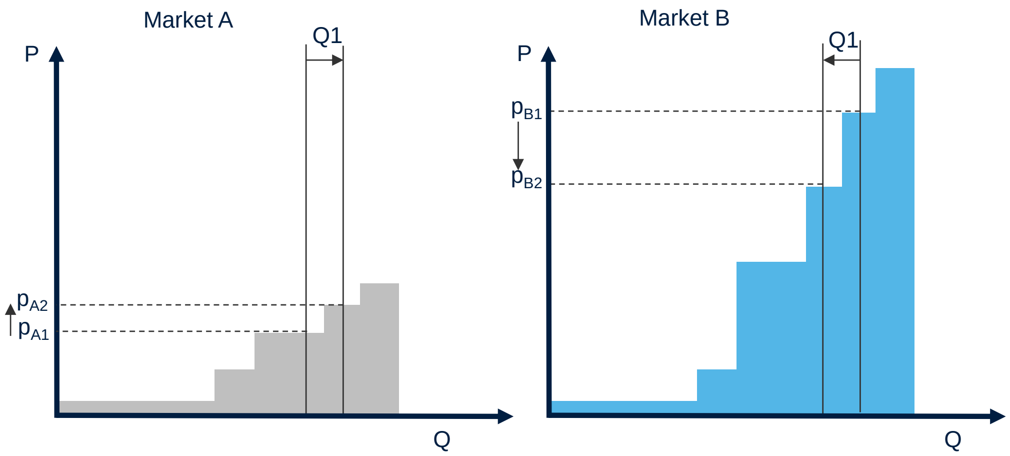
2.1.1 Welfare from cross-border trade

Where there is a price differential between two markets, trading would lead to net welfare gains, provided that transaction costs are less than the benefits from the trade. This holds for electricity too, where the primary benefit from trade is often referred to as the ‘merit-order effect’.

In this section, we first discuss welfare without reference to the associated transaction costs, therefore focusing on ‘gross welfare’. Transaction costs and a measure of net welfare are discussed in section 2.1.4.

By integrating markets and enabling trade between them, a more expensive plant in one country can be replaced with a more efficient one in another. Therefore, trade allows the least-expensive plants overall to be chosen, rather than the least-expensive plants from within one market only. This is illustrated in Figure 2.2. Here, the initial price in market A (P_{A1}) is much lower than in market B (P_{B1}). By exporting quantity Q1 from A to B, welfare gains can be achieved.

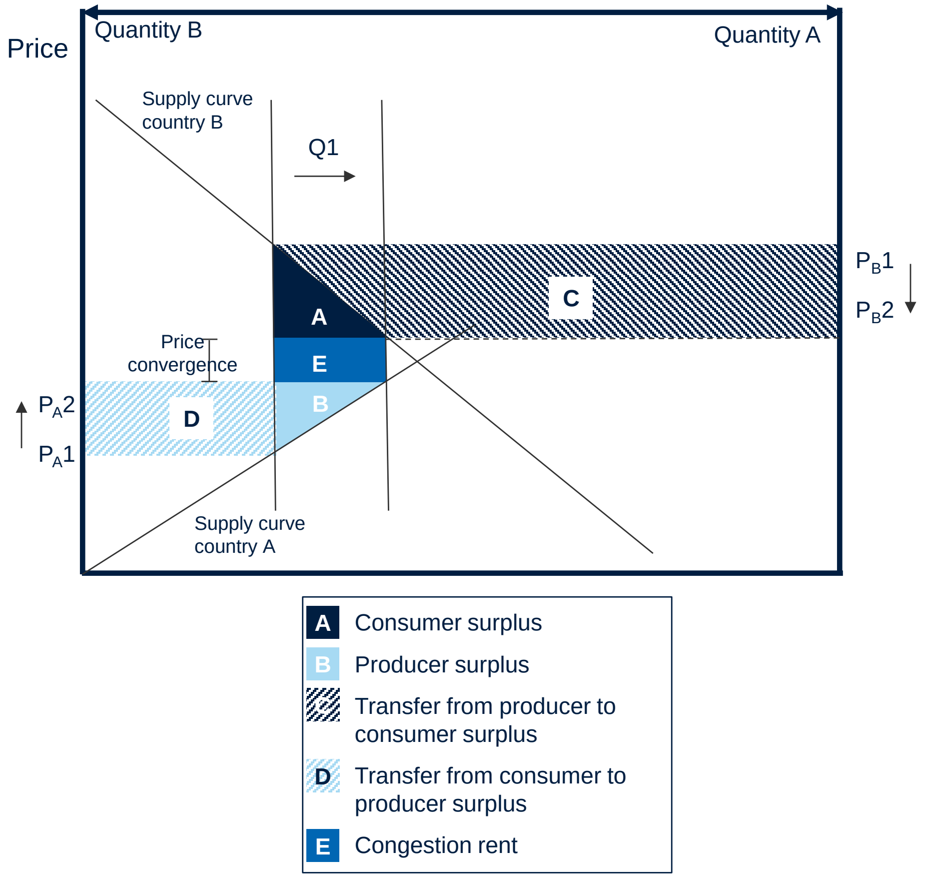
Figure 2.2 The merit-order effect



Source: Oxera.

The actual welfare gains are illustrated in Figure 2.3 below.

Figure 2.3 Welfare gains from cross-border electricity trade



Source: Oxera.

Figure 2.3 is a version of a supply and demand diagram showing two markets in one diagram. Market A is shown in a standard way with quantity increasing from left to right; for market B, quantity is increasing from right to left. Therefore, both supply curves are upward-sloping.

As is common when analysing electricity markets, the demand curves are assumed to be perfectly inelastic (e.g. vertical), which simplifies the welfare calculation and allows the same demand curve to be used for both countries in Figure 2.3. The shaded areas show transfers between different groups. In market A, prices rise, causing a welfare transfer from consumers to producers. The opposite happens in market B, where prices decrease due to the import of electricity, and welfare is transferred from producers to consumers. In addition, there is:

- an overall consumer surplus since, taking into account both markets, prices are overall lower than before;
- an overall producer surplus since the plants in country A that are being used as a result of the increased demand from across the border are more profitable than those in market B that are being replaced;
- a congestion rent, which occurs because the exported quantity is not actually sold at the price in its own market but at the (higher) price in the other market.

The welfare gain from trade is represented in Figure 2.3 by the areas A+B+E. The areas D and C are welfare-neutral, since they constitute a transfer from consumers to producers (D) and producers to consumers (C) respectively. The congestion rent is zero when absolute price convergence is achieved. This is also evident from the figure—area E vanishes if trade continues until the point where the supply curves intersect. This is the point at which gross welfare is maximised. Trade would not occur past this point. Note, however, that this might not be the socially optimal position because it ignores the transaction costs associated with these trades.

2.1.2 Output measure

To design an incentive based on welfare, an output measure is needed that is:

- observable and objective (not open to manipulation);
- directly linked to social welfare.

Several potential output measures were considered as part of this study. Their advantages and disadvantages are summarised in Figure 2.4.

Figure 2.4 Potential output measures for a market facilitation incentive

Price convergence + Simple and data easily available - Noisy and fluctuates for different reasons	**Cross-border flows** + Simple to observe and estimate - Not directly related to welfare
Congestion rent + Simple to calculate and related to welfare - Relationship to welfare not straightforward (increases then decreases with welfare)	**Welfare in both markets** + Consistent with the policy objective - Bid curves for both markets needed to estimate welfare

Source: Oxera.

These potential output measures can be directly linked to the welfare diagram in Figure 2.3 above.

- Price convergence and cross-border flows (Q1 in Figure 2.3) are very simple to measure, but they do not have a direct relationship to overall welfare.
- Congestion rent (E in Figure 2.3) is a combination of these two (the price differential multiplied by cross-border flows) and therefore jointly captures flows and price differences. It is also linked to welfare. As shown in Figure 2.3, congestion rent is zero at the point of price convergence, which is also where gross welfare is maximised. However, the relationship between congestion rent and the welfare impact is not straightforward, as it can increase or decrease with welfare. As an example, when no trade occurs,

congestion rent is also zero. As soon as some trade occurs, the congestion rent becomes positive (and therefore increases with welfare). However, once prices have fully converged, congestion rent also becomes zero. Therefore, at some point congestion rent starts decreasing with welfare until it is zero when prices have converged and welfare is maximised. Because of the complexity of the relationship to welfare, we do not see an obvious way to design a welfare-maximising incentive on the basis of congestion rent.

- The most straightforward output measure would be welfare itself (A+B+E in Figure 2.3). Estimating welfare requires more data than the other approaches since bid curves are needed for both markets. However, in principle this data is available from electricity exchanges. Since these exchanges are strictly regulated when it comes to their handling of market data, they are a well-recognised and reliable data provider.

Our preferred approach is therefore to use welfare created in both countries directly as an output measure. Empirical estimates of welfare from trades are presented in the following section.

2.1.3 Empirical analysis

In August 2015, the European Commission acknowledged the benefits of a common market for electricity, implementing a framework for a common bidding zone.[13] Already before market coupling took place, interest in quantifying welfare gain grew among academics and scholars alike. Using different methodologies and timeframes, several studies attempted to calculate the gross welfare from intra-European electricity trade. For instance, booz&co[14] estimated the market coupling to benefit consumers by €2.4bn–€4bn per year.

Similar to the empirical literature, Oxera has carried out an analysis of the gross welfare achieved through trade, as well as the additional welfare that could have been achieved with more trade. Based on historical data from 2018, our analysis has been carried out for the German/Dutch border in isolation (i.e. ignoring any knock-on effects in the rest of the Central and Western European market).

The following data was used in the analysis:

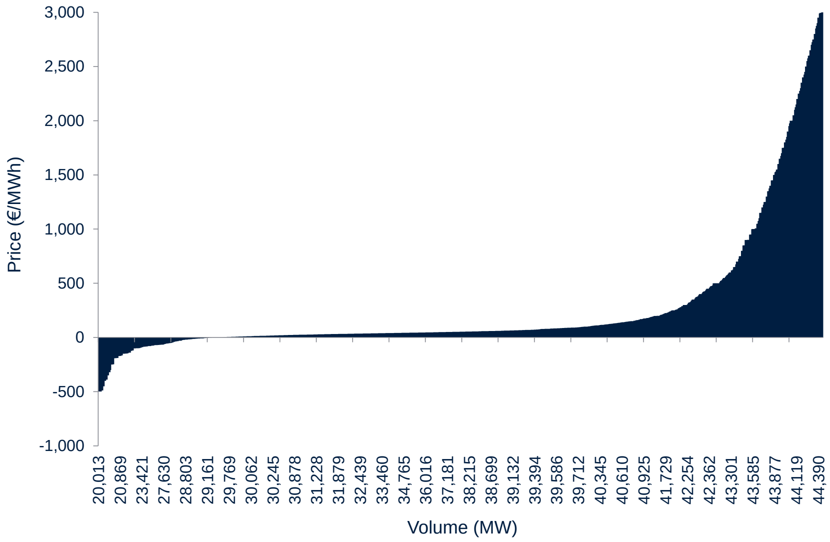
- hourly data on German and Dutch bid curves, sourced from the European power exchange EPEX;
- hourly data on commercial flows and prices from smard.de.

Bid curves for the two markets for an example hour are shown in Figure 2.5 below. The shape is as expected, with more extreme bids at the lower and upper ends.

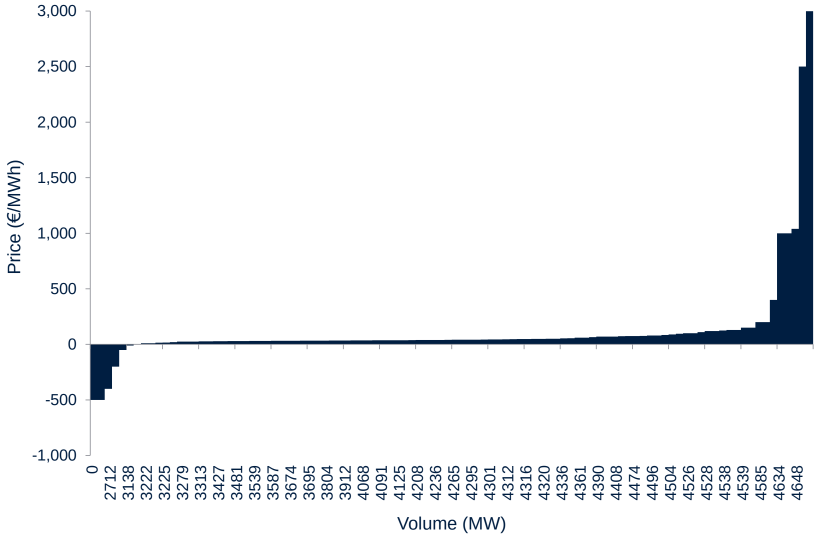
[13] European Commission (2015), 'New electricity market rules allow efficient EU-wide electricity trading', accessed 20 March 2019.
[14] Booz & Company (2013), 'Benefits of an integrated European energy market: Final report', prepared for the European Commission, July.

Figure 2.5 Bid curves for Germany, Austria, Luxembourg and the Netherlands

Germany, Austria and Luxembourg



The Netherlands



Note: Example from 18 January 2018, 17:00.

Source: Oxera analysis of EPEX data.

To estimate the welfare gains from trade for the German/Dutch border, we carried out the following steps for each hour.

1. Using the bid curve data, as seen in Figure 2.5, in combination with the observed wholesale market price in both markets, the historical observed clearing position on the bid curves was determined.
2. The historical market position as calculated in step 1 already contained the historical cross-border trade that actually took place. To estimate the hypothetical position had there been no trade, we subtracted the quantity of trades that occurred in this particular hour using data on commercial flows[15]

[15] The commercial trade is not a perfect measurement of the factual transfer of electricity between these two markets, but is the second-best option, after flow-based decomposition data, which is available for the Netherlands but not for Germany.

between the markets. This allowed us to identify a ‘counterfactual’ zero-trade quantity and the corresponding zero-trade prices in both markets.

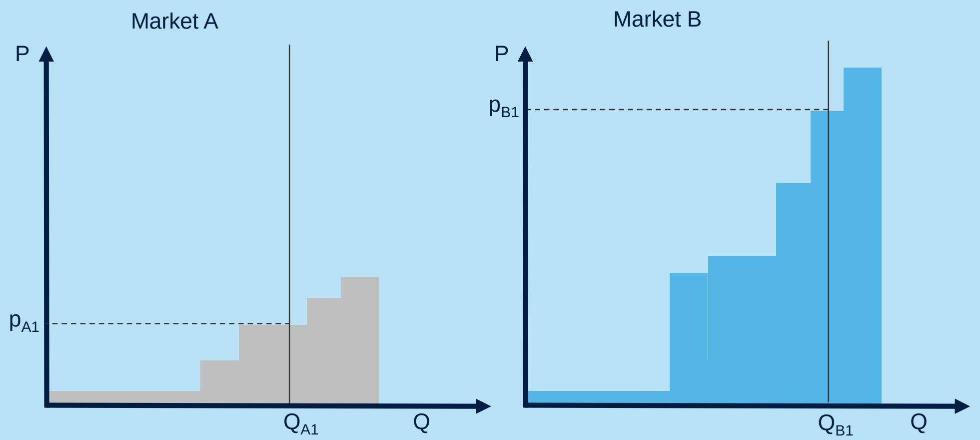
3. Starting from the ‘counterfactual’ zero-trade position in both markets, we allowed for 1MW of trade. This shifted the quantity in the market with higher prices to the left, and vice versa in the market with a lower price. The bid curves allowed us to calculate new prices and the welfare gain from the 1MW of trade.

4. The previous step was repeated until full price convergence was reached, recording successive gross welfare gains. This gave us a function linking the quantity traded with the welfare gain from trade that would be achievable.

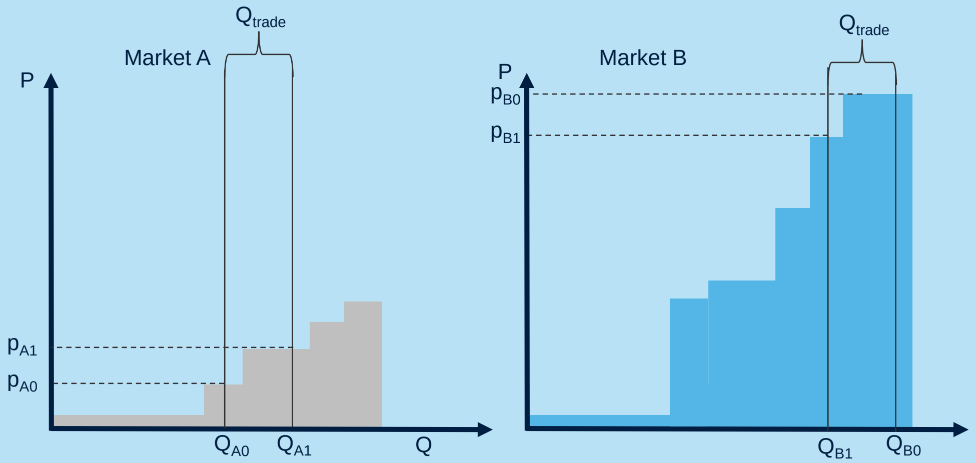
This methodology is illustrated in Box 2.1.

Box 2.1 Calculating welfare gains from trade: methodology

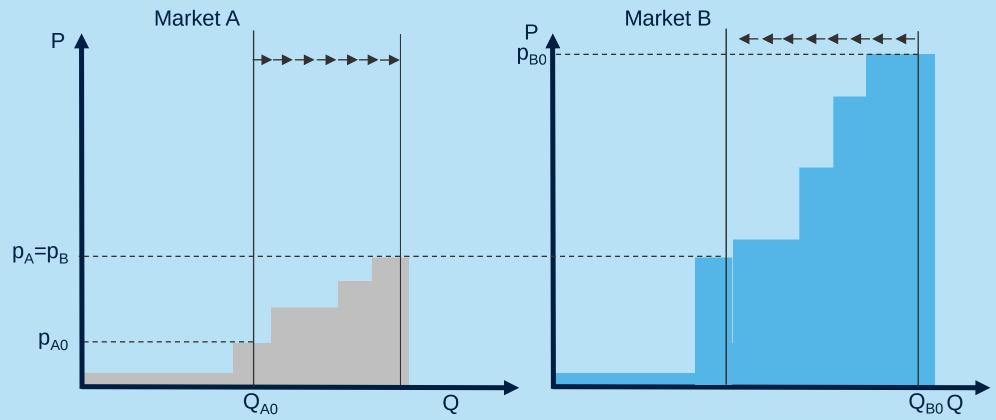
Step 1: Find the position on the bid curves given historical prices and quantity. Historical trade in this hour is Q_{trade}.



Step 2: Use historical trade in this hour (Q_{trade}) to infer the ‘counterfactual’ zero-trade position. This deliberately ‘forces’ trade in the wrong direction in order to find the position that would have occurred in the absence of the trade.



Steps 3 and 4: Starting from the ‘counterfactual’ zero-trade position, incrementally allow for more trade to occur and calculate the resulting welfare change. The maximum welfare gain is reached when prices have converged.



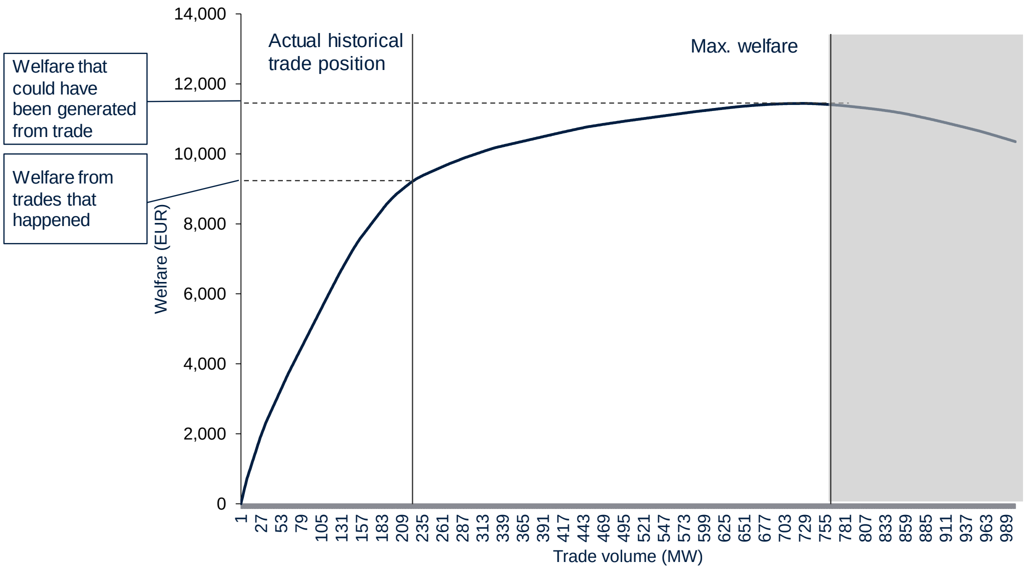
At each incremental step the welfare change is recorded, resulting in a function that links additional trade to the welfare achieved.

The assumption of using bid curves to calculate welfare is that bids represent the marginal costs of the respective technologies. While this is a sensible assumption for bids around the centre of the bidding curve, it might be less so at the edges. Particularly for the Netherlands, the welfare estimate includes some bids at €3,000 per MWh, which are most likely to be strategic, potentially leading to inflated gross welfare figures. Furthermore, as we consider only one border in isolation, our model does not allow for alternative markets to replace the missing electricity imports. This means that the counterfactual zero-trade position assumes that these strategic €3,000 per MWh bids would be accepted if demand is sufficiently high. In reality, the required electricity might be sourced from other countries, or there might be market entry.

Proceeding according to the outlined methodology, we calculated the welfare gain resulting from each additional 1MW of electricity traded, starting from the counterfactual zero-trade position.[16] Figure 2.6 below shows such a gross welfare curve for an example hour (18 January 2018, 17:00). The maximum is reached where price convergence between the two markets occurs. After this point, the welfare gain from more trade in the same direction decreases. This trade would now go in the wrong direction and as a result would not actually occur; this is shown on the curve below for illustration only.

[16] We do not calculate total gross welfare but gross welfare from trade. Quite naturally, the electricity markets in Germany and the Netherlands by themselves produce considerable welfare, even in the absence of commercial trade.

Figure 2.6 Gross welfare curve on 18 January 2018, 17:00

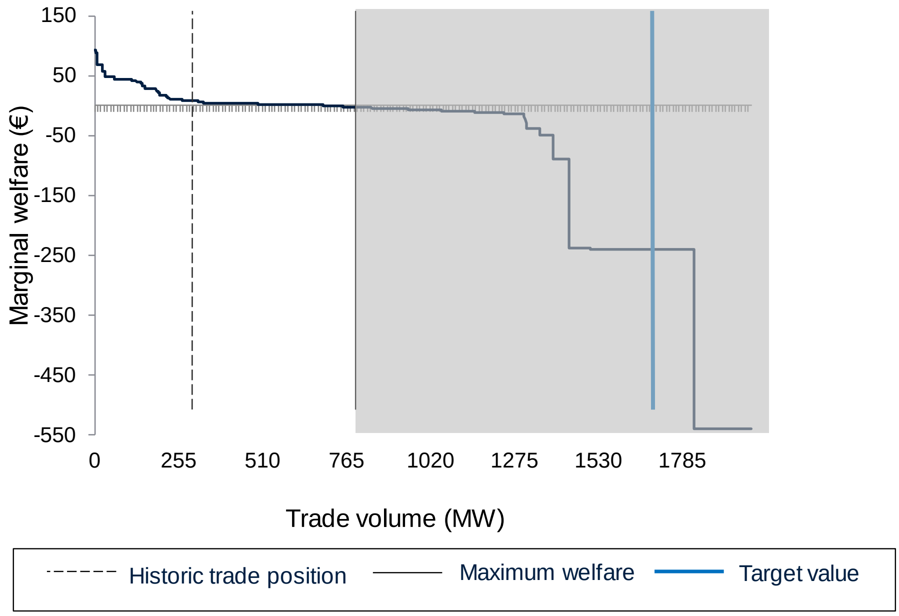


Note: The part to the right of the maximum welfare is for illustration only. Trades would not occur in reality past the maximum point since this would mean that electricity is traded from the country with lower prices to that with higher prices.

Source: Oxera analysis based on bid data for the Netherlands and Germany from EPEX; price and trade data taken from smard.de.

Figure 2.7 shows a different visualisation of the same effect: the marginal welfare curve. It shows how much each additional 1 MW of trade adds to the gross welfare, therefore displaying the slope of Figure 2.6. Here, the maximum is reached where the marginal curve is zero—i.e. where the slope of Figure 2.6 is zero.

Figure 2.7 Marginal gross welfare curve on 18 January 2018, 17:00



Note: The part to the right of the maximum welfare (where the marginal curve becomes negative) is for illustration only. Trades would not occur past this point since this would mean that electricity is traded from the country with lower prices to that with higher prices.

Source: Oxera analysis based on bid data for the Netherlands and Germany from EPEX; price and trade data taken from smard.de.

For each hour, the following figures are calculated:

- gross welfare generated at the factual trade position;
- maximum gross welfare achievable through trade;
- trade at which maximum gross welfare would have been realised.

The aggregated results for 2018 are summarised in Table 2.1.

Table 2.1 Gross welfare results for 2018 (€m)

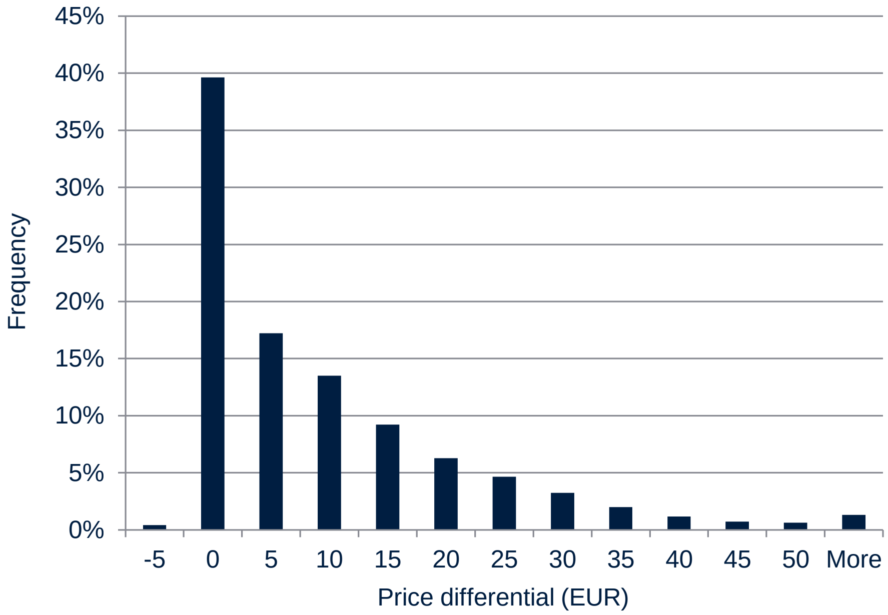
Maximum welfare	Gross welfare from factual trade	Additional welfare achievable
26,166	26,154	12

Source: Oxera analysis based on bid data for the Netherlands and Germany from EPEX; price and trade data taken from smard.de.

The results indicate that the greatest part of welfare gains from trade is already realised today. The current trade volume achieves c. 99% of possible welfare gains from trade. This is to some degree exacerbated by extreme bids at the edges of the bid curves. As noted above, the methodology assumes that bids are cost-reflective, which is unlikely to be the case for extreme bids. In a regulatory application of this model, unrealistic bids could automatically be filtered out such that they do not distort the welfare calculation. Nevertheless, there is still a substantial amount of welfare to be gained from trade at this border alone, of around €10m per annum.

Overall, price convergence at the German/Dutch border is already fairly high, as shown in Figure 2.8, which explains why the largest proportion of welfare is already being achieved.

Figure 2.8 Histogram of the price differential between the Netherlands and Germany, Austria and Luxembourg, 2018

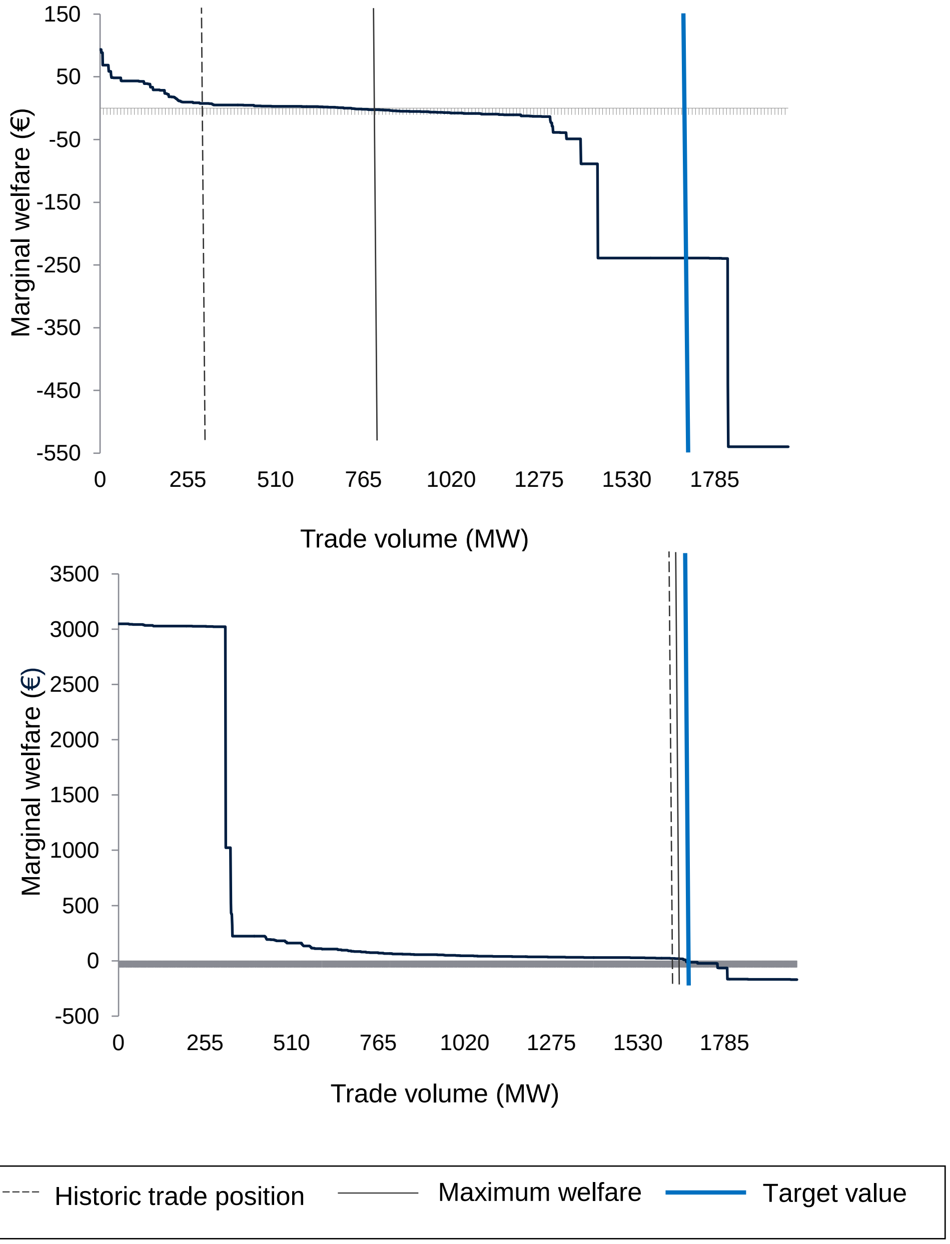


Note: Only until the end of September 2018 (bidding zone split). The category labels are upper bounds—for example, 0 means the proportion of hours during which the price differential was greater than 5 and smaller or equal to 0.

Source: Oxera analysis based on smard.de.

This analysis indicates that a fixed target on cross-border capacity to be made available cannot be optimal at all times. This is because the time-specific market conditions determine the gross welfare to be gained from trade. For example, if prices are very similar already for other reasons, there is not much welfare to be gained from trade, and the capacity could be better used elsewhere—as illustrated by the two example hours of the same day shown below.[17] The 70% NTC target might be very close to the total maximum in some hours, but differ substantially from the optimum in others.

Figure 2.9 Comparing marginal welfare curves and 70% NTC targets across hours



Note: The top graph shows the marginal welfare on 18 January 2018 at 17:00, the bottom graph at 03:00. The target value is the 70% NTC target. Flow-based parameters are actually used for this border, rather than NTC. The figures used here are long-term allocations that represent the

[17] NTC is not actually used on borders that are part of market coupling. Instead, flow-based parameters are used. However, TenneT publishes long-term capacities that represent the minimum day-ahead capacities but do not take into account curtailment. These figures are therefore not accurate but give an indication of the transfer capacity.

minimum day-ahead capacities, ignoring curtailments. It is therefore a rough estimate, rather than a precise flow-based value.

Source: Oxera analysis based on bid data for the Netherlands and Germany from EPEX, price and trade data from smard.de, and NTC data from Tennet.eu, accessed 17 May 2019.

Similarly, the costs associated with making a fixed amount of capacity available vary hour by hour. This cost component is missing from the analysis in this section, but is discussed below.

2.1.4 Transaction costs of cross-border trade

Facilitating cross-border trades is not costless for TSOs. Even though the interconnector itself may not be at capacity, other, more congested, lines act as a bottleneck. To increase the capacity available for cross-border trade, the TSOs must apply redispatch measures. When no more redispatch is available, the TSOs have to start countertrading in order to facilitate more cross-border trade. This means they essentially let the market carry out the cross-border trade and then buy back the capacity.

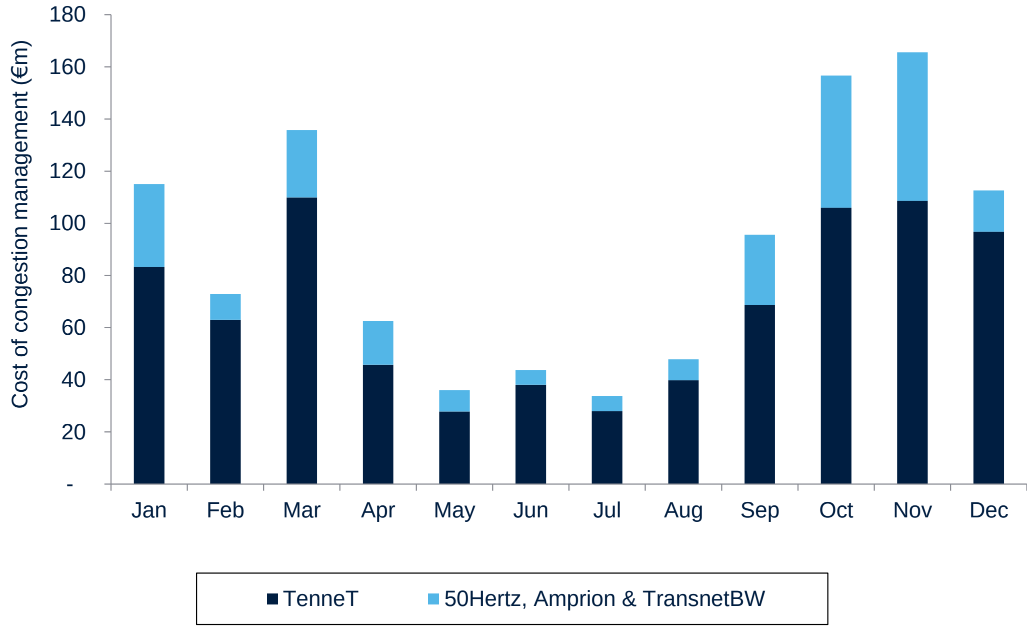
These costs need to be related to gross welfare in order to understand where the overall net welfare position might be. However, obtaining cross-border-specific cost data on an hourly basis is not straightforward. In the Netherlands, a flow-based tool is being used to decompose redispatch costs, but this is not available in Germany. Moreover, to map the costs of cross-border trade to welfare, it would be necessary to know hypothetical costs—i.e. the cost to the TSO of providing 1MW more or less cross-border capacity.

For the purpose of this study, therefore, it is not possible to map a cost curve to the welfare curves shown above. Nevertheless, data available in the public domain has been analysed here in order to understand the overall magnitude of the costs involved.

In 2018 overall redispatch and countertrading costs in Germany were just over €1bn.[18] This figure captures all redispatch costs, with most costs therefore not being directly related to cross-border trade. TenneT accounted for the majority of total redispatch and countertrading costs (€816m), as shown in Figure 2.10.

[18] ENTSO-E Transparency Platform.

Figure 2.10 Cost of congestion management in Germany, 2018



Note: These costs are not border-specific.

Source: Oxera based on ENTSO-E Transparency Platform.

ENTSO-E has published the costs of cross-border trades as part of its bidding zones technical report.[19] However, these costs are not for a specific border, but for an entire bidding zone. In 2017, these costs accumulated to around €1bn for Germany, Austria and Luxembourg, and around €50m for the German/Dutch border.

To obtain a rough indication of the proportion of these costs that is attributable to the German/Dutch border, we adjusted the costs in line with the proportion of flows that the border accounts for. For this border, the analysis indicates that the costs may be around €100m–€150m per annum. This approximation may not be accurate as it does not account for differences in congestion levels between different borders.

Table 2.2 Total annual cost of cross-border trades and implied costs specific to the Dutch/German border

	Germany			Netherlands		
	Costs (€m)	Proportion of flows of DE/NL border	Implied costs for DE/NL border (€m)	Costs (€m)	Proportion of flows of DE/NL border	Implied costs for DE/NL border (€m)
2015	890	16%	140	30	49%	15
2016	677	11%	72	80	48%	39
2017	1,000	8%	78	50	49%	25

Source: Oxera analysis based on ENTSO-E (2018), 'Bidding zone configuration technical report 2018', October.

2.1.5 Designing an incentive

This section combines the insights of the above analysis to provide input into how output-based regulation could be used in future in terms of the specific

[19] ENTSO-E (2018), 'Bidding zone configuration technical report 2018', October.

design options. First, we discuss the challenges that may arise when incorporating transaction costs that are currently treated as (mostly) pass-through. Then, a potential incentive formula is presented. Here, the advantages and challenges of various calibrations, particularly with respect to the baseline, are discussed.

Incorporating transaction costs

The basic idea of an output-based incentive, as illustrated in Figure 2.1, would not require regulators to know the TSOs' costs of providing cross-border capacity. The regulator could set the incentive in line with gross welfare and rely on the TSOs to make the optimal decision based on their knowledge of their own costs. However, this mechanism fails if costs are passed through, as there would be no incentive to control costs. An incentive based on gross welfare could therefore lead to an overprovision of cross-border capacity. Under the current regulation, redispatch costs are indeed passed through, at least for now, so a straightforward incentive based on gross welfare would not necessarily work. This issue can be resolved in one of two ways:

- incentivising redispatch and counter-trading costs;[20]
- basing the incentive scheme on net welfare by subtracting transaction costs from the gross welfare estimate.

A simple example of these two approaches is provided in Box 2.2.

Box 2.2 Example incentive under the two options (marginal welfare = €100)

	Incentivise costs from cross-border trade	Incentive based on net welfare
Incentive	TSO gets €100 for the next MW made available for trade	TSO gets €100 minus the marginal cost, as estimated by the regulator
TSO decision	Facilitate trade if marginal costs ≤€100	Facilitate trade if €100 minus estimated marginal cost ≤0 Actual costs are pass-through, and therefore do not affect the decision
Outcome	Efficient if TSO knows its own marginal cost	Efficient if regulator estimates marginal cost correctly

Source: Oxera.

The first option may be preferable as it would not require the regulator to estimate the costs of market facilitation. While data on redispatch costs is published, linking it to specific cross-border trade would require techniques such as flow-based decomposition, which the TSOs might be better suited to carry out.

A potential complication of the first option it that the TSOs face some uncertainty around the welfare to be gained from trade. This is because that welfare materialises only after the TSOs have decided how much capacity to make available. They would therefore have to form an expectation of the likely welfare gain they are creating.

[20] This could be done by introducing a separate incentive for SO costs whereby the TSOs retain a share of any out-/underperformance.

Setting the parameters for an output-based incentive

Under either of the above option, the market facilitation incentive payments to TSOs would be calculated according to the welfare created relative to the baseline welfare. Risks and rewards might then be shared between the TSOs and consumers according to a sharing factor, calculated as follows.

$$Market\ facilitation\ incentive_t = \alpha \times (Welfare_t - Baseline)$$

where α is the sharing factor, and t is time.

Setting the baseline

- A key decision is how the baseline should be set. This determines the strength of the incentive and how much this incentive could contribute to a TSO's allowed revenue. Two options at the extreme ends are:
  - resetting the baseline every year to reflect the welfare created in the previous year;
  - setting the baseline to zero.
- The former would be an output-based incentive encouraging a change in behaviour. The closer the markets move to price convergence, the lower the payments through this incentive. In contrast, the second option is closer to output-based remuneration, where the TSOs would receive a share of the total welfare they generate.[21] In practice, a good balance between these two structures could be considered to set the baseline at the start of the regulatory period and allow the TSO to retain (a share of) the outperformance during the entire price control period.
- In principle, an incentive that directionally sets the right amount of cross-border capacity to provide in the short run can also help in determining long-run needs, provided that the incentive is credible. This requires political,[22] regulatory, and market acceptance. The incentive structure would be similar, with the only difference being that the TSOs can keep any outperformance for longer.

Determining risk and reward

- The sharing factor (α in the above formula) determines how much the TSOs retain of the additional welfare generated relative to the baseline and how much is shared with consumers. A higher sharing factor limits both the risk and the rewards for companies.
- In addition, the TSOs' exposure to risk and rewards can be managed using caps and collars.

Geographical scope and bidding zones

Cross-border trade requires capacity to be available on both sides of the interconnection. This means that there are interactions between the TSOs, and any welfare gain created from trade does not depend entirely on a TSO's own actions. This system would therefore ideally be applied across the whole of Europe, or at least a region such as Central West Europe, such that the TSOs

[21] The sharing factor refers to sharing risks and rewards between the TSOs and consumers. The TSOs on both sides of the border would also need to arrange how to share the gains between them.
[22] Political acceptance at a national level may be challenging as the welfare gains could materialise in another country, rendering the approach politically unpopular.

can together create an optimum and negotiate to share the benefits. However, even if the system applied only to the TSOs in one country, they could form bilateral agreements with neighbouring TSOs such that the system could still work on a smaller scale.

2.1.6 Summary and interaction with current targets

The output-based approach to promote cross-border trade suggested in this section envisages incentivising TSOs based on the welfare created by the trade they facilitate. Since the start of this study, a new target for cross-border trade has been introduced at the EU-wide level. This specifies that TSOs should make 70% of installed capacity available for cross-border trade.[23]

The analysis conducted in this section suggests that such an inflexible target is unlikely to be welfare-optimal. Depending on the possible gains from trade and the costs of providing transfer capacity to the market, the welfare-optimal capacity could vary around the 70% target, being above it in some hours and below it in others.

This raises the question of whether the proposed approach can be used under this new regulation, or whether the two do not fit together. In theory, the output-based approach could be used together with an additional constraint of 70%. This would mean that:

- during hours when the welfare-optimal position is above 70%, the output-based approach would (correctly) incentivise TSOs to provide more capacity than the fixed amount;
- during hours when the welfare optimal position is below 70%, the TSOs would still be required to make 70% of capacity available for cross-border trade. In this case, the costs would be higher than the welfare generated, and therefore this is not the optimal position;
- in hours when the welfare optimal position is exactly 70%, both the fixed target and the output-based incentive have the same effect.

If it is possible to accurately design an incentive based on welfare, the 70% target would not be needed, and would even lead to sub-optimal outcomes in hours when achievable welfare gains are not that high compared to costs. The output-based incentive presented in this section is therefore likely to be more favourable in welfare terms than the alternative: the 70% target.

2.2 RES curtailment incentive

RES-infeed can save CO_2 emissions that would have been emitted by conventional generation, but can also cause substantial redispatch costs if there are constraints in the network.

In this section, we propose an output-based solution by pricing RES curtailment such that the associated costs and CO_2 savings are captured. This would allow the TSOs to internalise the trade-off between increased costs and lower CO_2 emissions. As with market facilitation, the incentive would vary from hour to hour, depending on the constraints present in the network. This approach is therefore likely to be more economically efficient than the current inflexible rules of priority dispatch for renewables.

[23] Regulation (EU) 2019/43 of the European Parliament and of the Council of 5 June 2019 on the internal market for electricity, Article 16(8).

2.2.1 Issues and current rules

Redispatch is a TSO action to relieve constraints in the network when too much renewable energy is generated in a different location to where it is being demanded. In Germany, for example this situation arises on windy days when most electricity is generated in the north of the country and then needs to be transported to the south. When the network becomes too congested, generation needs to be ramped down in the north and up in the south.

The current rule around priority dispatch for renewables in Germany requires the TSOs to exhaust conventional options before curtailing any renewables.[24] This approach is not flexible enough to account for the cost implications of different curtailment orders at different times. In particular, the cost of relieving 1MW of congestion depends on:

- the costs and revenues of ramping generators up and down;
- the location of the plant relative to the point of congestion.

Usually, the lowest-cost redispatch option is used first, and then more expensive options are used as needed. So, as with normal dispatch, redispatch follows a merit-order logic. With priority dispatch for renewables, RES-infeed cannot be curtailed until this is the last resort, even if it would be the lower-cost option.

2.2.2 Output-based incentive

As with market facilitation, a more flexible approach with respect to RES curtailment could be used to achieve better outcomes for society. The premise is that society values:

- a reduction in CO_2 emissions; and
- lower electricity costs.

The current priority dispatch rule in Germany focuses on the former. While CO_2 reductions are clearly important, if they come at a very high cost, it might be better for society to reduce costs in some hours instead, and, for example, to invest the saved costs in projects to lower CO_2 emissions elsewhere.

An efficient approach to ensure that the TSOs internalise this trade-off is to introduce a ‘price’ per MWh for RES curtailment. This price would reflect both:

- the additional CO_2 emissions caused by the curtailment and the associated cost to society of these emissions; and
- that curtailment is costly because generators need to be compensated for ramping up/down compared to their market position. These costs are treated as pass-through for the TSOs.

If the price is set correctly and captures the value that society places on CO_2 emissions, this would incentivise TSOs to efficiently internalise the trade-offs associated with curtailment.

CO_2 emission reduction

The electricity price already contains a CO_2 component in the hours when the marginal plant is a thermal generator. This plant would be paying the CO_2

[24] Erneuerbare Energien Gesetz 2017 (EEG), para. 14.

price, which would be priced into its bids. However, this captures the CO_2 emissions of the marginal plant only. Any additional CO_2 emitted because of RES curtailment would need to be calculated and included in a price for RES curtailment. This part of the suggested 'price' would be calculated as the additional CO_2 emissions from the curtailment action, multiplied by the price of CO_2 certificates.

Curtailment cost reduction

Curtailment in itself is costly because generators can be entitled to receive compensation for deviating from their market position. An example of this is the curtailment of production from a wind farm.[25] Rather than treating these costs as pass-through, the TSOs could be incentivised to reduce the amount of electricity curtailed.

Bringing it all together

Under the proposal considered in this section, the price for curtailment would capture the CO_2 and the cost aspects of renewables. It would incentivise two actions:

- not curtailing RES because of the associated CO_2 emission reductions;
- taking into account network constraints when choosing which plant to curtail.

The output-based approach compared to the current system is summarised in Table 2.3.

Table 2.3 RES curtailment incentive

Output	Current system	Output-based
Environmental	Priority dispatch	Price of additional CO_2 emissions as a result of curtailment
Cost saving	None (pass-through)	Bonus for avoided curtailment
Overall	Decision based on fixed rule; no trade-offs taken into account	Both aspects are combined into a single price. This sends different signals depending on the network constraints in any given hour

Source: Oxera.

The two price components would then need to be calibrated correctly in order to ensure that the incentive is balanced.

[25] Thermal generators might pay the TSOs to be ramped down, but the overall net curtailment payments by the TSOs would still be expected to be positive.

3 Fixed OPEX/CAPEX share

In this section we describe the proposed fixed OPEX/CAPEX share (the FOCS) measure. This measure ensures that all costs, be they for operational measures (OPEX) or investment measures (CAPEX), are treated equally. This equal treatment means that the regulated company can choose the cost-optimal solution for any given network problem, undistorted by the regulatory system.

We first set out the problem that would need solving, before exploring how it could be solved in theory. What then follows is a practical description of how the approach could be implemented in Germany, with a practical example demonstrating the feasibility of the approach. We conclude with some further discussion of implementation challenges.

3.1 Why we need a fixed OPEX/CAPEX share

Oxera argues that the FOCS might be appropriate, for the following reasons:

- as set out below, there is a bias towards CAPEX solutions, for a number of reasons, possibly because it has been treated ‘more favourably’ than other costs, or due to OPEX being disadvantaged;
- this bias matters now more than in the past because of the availability of new technological solutions for electricity networks that are (i) OPEX-heavy and (ii) did not exist previously;
- compared to an OPEX return that has to be balanced against a CAPEX return, the FOCS is self-stabilising. Unlike direct incentives for smart solutions, the FOCS is simple and less based on micromanagement by the regulator. Moreover, it makes the regulatory system more technology-neutral.

3.1.1 What explains the possible CAPEX bias?

There are several explanations for why the regulatory system in Germany and the Netherlands might have a CAPEX bias, and may not be technology-neutral.

Practical limits to the estimation of the cost of equity

One reason for the existence of a CAPEX bias would be that the allowed return on equity is marginally higher than the real cost of equity (the risk-adjusted return that equity investors expect to receive). Thus, the company receives not only accounting profits, but also actual economic profits over and above pure compensation for the risk that investors bear. Hence, to solve a particular network problem, the company would prefer CAPEX investments over OPEX solutions, as the latter do not provide an economic return.

While, in theory, applying the capital asset pricing model (CAPM) should ensure that the allowed return on equity is exactly equal to the risk-adjusted actual cost of equity, in practice the allowed return may be marginally higher. This is because, while the cost of debt can be observed in capital markets by looking at various market indices, the cost of equity cannot be observed directly and needs to be estimated. Every estimation necessarily contains some estimation error such that the estimated value can be above or below the actual cost of equity.

Slightly overestimating the allowed cost of capital compared to the true cost of capital will have some cost, in that investors will be overcompensated. Underestimating the allowed cost of capital means that regulated companies could stop investing because they cannot finance their investments. In earlier work,[26] Oxera explored the optimal way to estimate the cost of capital that strikes a balance between risking the damage of stopping investments and the unwanted additional return to investors.

Setting the allowed rate of return is a contentious debate in almost every jurisdiction in which it is applied. There are ongoing debates in the Netherlands as well as in Germany, and this report does not comment on whether the currently suggested cost of equity or weighted average cost of capital (WACC) figures might be too high or too low. A recent study for the regulator BNetzA attests a CAPEX bias for the German ARegV system.[27]

OPEX disadvantage

Even if the regulator were able to estimate accurately the unobservable actual cost of equity, there may still be circumstances that would lead to the regulated company preferring CAPEX solutions.

A regulated company in Germany might not be able to recover its OPEX for a number of reasons, including the following.[28]

- There is a greater risk that the costs of OPEX solutions might increase during the five-year regulatory period. Such a solution might include, for example, payments to certain consumers to alleviate network constraints by providing demand-side flexibility. This higher risk comes from such payments being inherently more volatile in nature than predictable capital costs.
- There is a perception in the regulated industry that OPEX is more likely to be disallowed in BNetzA's cost audit than CAPEX. From an informational asymmetry point of view, this appears plausible because CAPEX programmes are typically more complex than OPEX programmes, and therefore scrutinising the latter might be easier.
- OPEX might be exposed to some risks too, for which the regulated company is not remunerated. While a generally accepted theory for an OPEX return has not yet been developed, there is some recognition of the risks relating to costs that are not CAPEX. For example, for the new electricity system operator function of National Grid, Ofgem (the energy regulator in Great Britain) has proposed a regulatory approach with 'cost pass-through with a margin', instead of the standard RAB*WACC approach. Under the proposed new approach, the costs of different system operator activities would be passed through, and the system operator would also earn a margin assigned according to the level of risk associated with the activity.[29]

In addition, even just the perception of a CAPEX bias might be sufficient to bring about this bias. In a survey of regulatory managers, Ofwat (the water sector regulator in England and Wales) found several additional reasons for a

[26] Oxera (2014), 'Review of the "75th percentile" approach', prepared for the New Zealand Commerce Commission.
[27] Consentec and Frontier Economics (2019), 'Gutachten zur regulatorischen Behandlung unterschiedlicher Kostenarten vor dem Hintergrund der ARegV-Novelle für Verteilernetzbetreiber', Untersuchung im Auftrag der Bundesnetzagentur Tulpenfeld 4, 53113 Bonn.
[28] Similar arguments hold for the regulatory frameworks in the Netherlands and elsewhere in Europe.
[29] Ofgem (2018), 'RIIO-2 Sector Specific Methodology Annex: Electricity System Operator', December, p. 23.

CAPEX bias,[30] mostly of a behavioural nature. One reason for such a bias was that, even if there were no actual bias, if decision-makers in companies think that CAPEX solutions have an advantage, the resulting decisions would be biased regardless.

3.1.2 New and OPEX-heavy network solutions may mean that the FOCS is important

Oxera does not attempt to predict the outcome of future technological developments and innovations in the network industry. However, we do argue that new technological developments should be exposed to a 'level playing field' (i.e. technology-neutral regulation), such that they can be used without disadvantaging the companies employing them.

There is a series of promising technical solutions that might become a substitute for capital investments. Some of these are being facilitated by technological progress, such as developments in battery technology, digitalisation and smart grids. For example:

- parts of the network could be run temporarily on an N-0 instead of an N-1 standard. For such a procedure to be safe, the TSO would need to have a precise view of the state of the network and access to a considerable amount of flexibility. However, N-0 would require an amendment to the current legal framework (the system operation guideline (EU)1485/2017);[31]
- load and renewable infeed could be curtailed as needed and then compensated for;
- flexibility could be obtained through contracts with battery operators and other providers of demand- or supply-side flexibility.

Some opportunities have been available for a long time and are only now increasingly being used—for example, temperature control on wires, which allows for temporary line overload.[32]

Another opportunity that is equally OPEX-intensive (and which features little in the discussions around an OPEX bias) is the use of assets that are written off already but are still functional.[33] Under the current system, companies might have the incentive to replace assets as soon as they are written off. This is because written-off assets do not attract an allowed regulatory return, but rather increase maintenance expenditure, which is OPEX.

3.1.3 FOCS might be the best available solution

One could attempt to correct a CAPEX bias in a number of ways, including through:

- direct incentives for particular technological solutions that would include OPEX or for the use of written-off assets; or

[30] Ofwat (2011), 'Capex bias in the water and sewerage sectors in England and Wales – substance, perception or myth? A discussion paper', May.
[31] Such an approach is called automated network management (*Automatisierte Systemführung*) and is described in more detail in Consentec (2016), 'Netzstresstest – Eine Studie im Auftrag der TenneT TSO GmbH', Abschlussbericht, 25 November.
[32] Agora Energiewende (2018), 'Toolbox für die Stromnetze - Für die künftige Integration von Erneuerbaren Energien und für das Engpassmanagement'.
[33] We are not implying that assets are systematically longer-lived than their regulatory asset life. The regulatory asset life can be seen as an expected lifetime of an asset, with some assets lasting longer and some less long. Assets that last longer than their expected lifetime should be used for longer because this is economically efficient.

- the introduction of an OPEX return; or
- attempting to set the allowed cost of capital exactly equal to the actual cost of capital.

In what follows, we argue than none of these possible corrections is ideal, and that the FOCS might be the best way to make the regulatory system technology-neutral.

Direct incentives for specific solutions could suffer from two main problems.

- Whoever decides on the technology to be supported, be it the regulator or policymakers, would be picking winners. This might stifle entrepreneurial thinking and innovation in the network industry. The hidden cost of such a policy is that other solutions, which might have been better, would not be developed or used.
- The extent to which the subsidised technologies are used would depend more on the level of the regulatory remuneration than on the actual usefulness of the technology. Defining the exact amount that would lead to the optimal use of the technology—e.g. that balances the advantage of CAPEX—is very difficult. For example, if the use of written-off assets is incentivised, this is likely to lead to assets being deployed for longer. There is a chance, however, that such a payment would not actually lower the costs for consumers. This is because, depending on the size of the payment, assets will be kept in operation for too long or not long enough.

The introduction of an OPEX return could have a similar disadvantage to that arising from the introduction of direct incentives. It needs to be balanced against the return on CAPEX, in order not to create a distortion one way or the other. Furthermore, as already noted, as yet there is no generally accepted theory for how to estimate an OPEX return, which would limit its applicability, particularly in a comparatively litigious regulatory environment.

Focusing on a CAPEX-only return, and reducing it to the point where the company does not make any economic profits, and therefore being indifferent between CAPEX and OPEX solutions, has risks and disadvantages as well.

- In particular during the course of a five-year period, the risk of setting the allowed cost of capital lower than the actual cost of capital, and hence discouraging investment, is significant.[34] This is a situation that regulators, seek to avoid, and for good reason (see section 3.1.1 above).
- It would still not balance out any OPEX risk, and hence a CAPEX bias would remain.

3.2 Theory

Under the FOCS, all costs are treated equally, be they expenditure on capital goods or on operational measures such as procuring flexibility.

In other regulatory discussions, for example in the UK[35] and Italy,[36] this has been called a 'TOTEX approach'. There is consensus among the community of

[34] Even if the BNetzA succeeded in setting the allowed cost of capital exactly equal to the actual cost of capital, capital market conditions might change. If the actual cost of capital goes up, the allowed cost of capital would be lower than the actual cost of capital, and investments by regulated companies would cease.
[35] Ofgem (2017), 'Guide to the RIIO-ED1 electricity distribution price control', January.
[36] Oxera (2016), 'Electricity network regulation in Italy moves towards a new paradigm', *Agenda*, February.

regulatory practitioners that the introduction of TOTEX regulation is a robust way to ensure overall efficiency.[37]

So why is it called the FOCS in Germany? When the UK introduced TOTEX regulation from 2010 onwards,[38] it started from a system in which OPEX and CAPEX were treated rather differently, with separate regulatory formulae and separate OPEX efficiency benchmarking.[39] Because the efficiency benchmarking, the regulatory formula and the capitalisation rule were changed to a TOTEX approach, the new system was referred to as 'TOTEX regulation'.[40] The UK also introduced forward-looking cost benchmarks on a TOTEX basis, a measure that goes beyond what we are proposing here.

Contrary to the RPI - X formula applied in the UK, the regulatory system in Germany already has some TOTEX elements that do not discriminate between CAPEX and OPEX. Both the regulatory formula and the efficiency benchmarking exercise were set up to be TOTEX from the start. For the introduction of a TOTEX logic (i.e. treat all costs the same), in Germany this is advantageous. The system does not need to be changed entirely; rather, with respect to capitalisation, the costs need to be treated equally (currently CAPEX is capitalised; OPEX is not). We explain in what follows how this can be done.

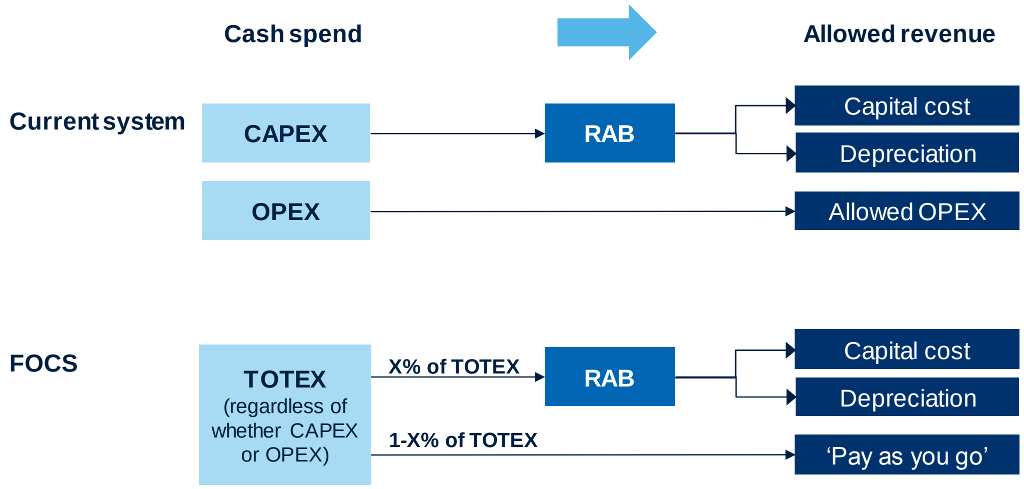
3.2.1 The concept of FOCS

The premise for the current capitalisation rule and for the FOCS is described in Figure 3.1.

At present, in the German and Dutch regulatory systems, CAPEX is capitalised and creates allowed capital costs and depreciation that are added to allowed revenues. OPEX is expensed directly (through the 'snapshot logic').[41] It is important to note that here the term 'CAPEX' refers to cash spent on capital goods. This differs from the definition used in German efficiency benchmarking for example, where CAPEX refers to the revenue part stemming from CAPEX.

[37] Florence School of Regulation (2019), 'EU Clean Energy Package', online course, 2nd edn, p. 39.
[38] Ofgem (2010), 'Handbook for implementing the RIIO model', 4 October.
[39] Ofgem (2010), 'RIIO: A new way to regulate energy networks: Final decision', October.
[40] The regulatory changes went beyond introducing TOTEX regulation; under RIIO, longer price control periods and output-based incentives were introduced as well.
[41] We are abstracting from efficiency assumptions (Xind and Xgen), and other elements of the regulatory formula, such as inflation.

Figure 3.1 Premise for FOCS—equal treatment of all costs



Note: 'Pay as you go' refers to costs that are recovered every year or during the control period, and are therefore treated similarly to OPEX in the current system.

Source: Oxera.

Under the FOCS, all expenditure would be regarded as TOTEX. In particular, this would include the costs of investment, maintenance and system operations, and the procurement of flexibility. A fixed share of these costs would then be added to the RAB, creating allowed capital costs and depreciation that are added to the allowed revenue. The balance of the costs would be expensed directly.

The FOCS would mean that a fixed percentage of cash spent on actual capital goods would be added to the RAB. Equally, a similar fixed percentage of cash spent on OPEX—for example, on flexibility measures or other smart solutions—would be added to the RAB. In doing so, and thereby treating all costs the same, the FOCS would make sure that the technology decision of the TSO is not biased by differing treatments of CAPEX or OPEX. Similarly, it would remove any need for the regulator, when undertaking the cost audit, to check whether certain costs are OPEX or CAPEX.

Another angle to this would be to ask why the rule of capitalisation in regulation should be different from capitalisation rules in other market-based industries (e.g. industries without substantial market failures). After all, in such industries, investments are capitalised and OPEX is counted directly as a cost in the profit and loss (P&L) account.

To understand this question, it is helpful to think about the role of accounts in market-based and regulated industries. In market-based industries, the revenue that a firm makes is determined only by whether the firm can find customers who value its product sufficiently that they are willing to pay for it. Accounts are maintained for record-keeping and monitoring purposes, and to understand costs in order to be able to make decisions. This is also why a market-based firm will naturally try to keep its cost down and choose the most efficient technological solution. Keeping costs down will typically increase profits for market-based firms.

Once a firm is regulated, incentives change. The accounting practices and how different costs are allowed to be accounted for can have an impact on the firm's allowed revenue. Simply put, a regulated firm may have an incentive to consider types of cost that are more likely to be recognised and remunerated by the regulator. This is why, under regulation, the accounting (and with it the regulatory) treatment of costs really does matter.

3.2.2 A numerical example

We demonstrate below, using a numerical example, the logic and potential effectiveness of the FOCS relative to the current German ARegV (standard ARegV). Since the regulatory system in the Netherlands is similar but slightly less complicated than the ARegV approach, there is reason to believe that the FOCS would be effective also in the Netherlands.

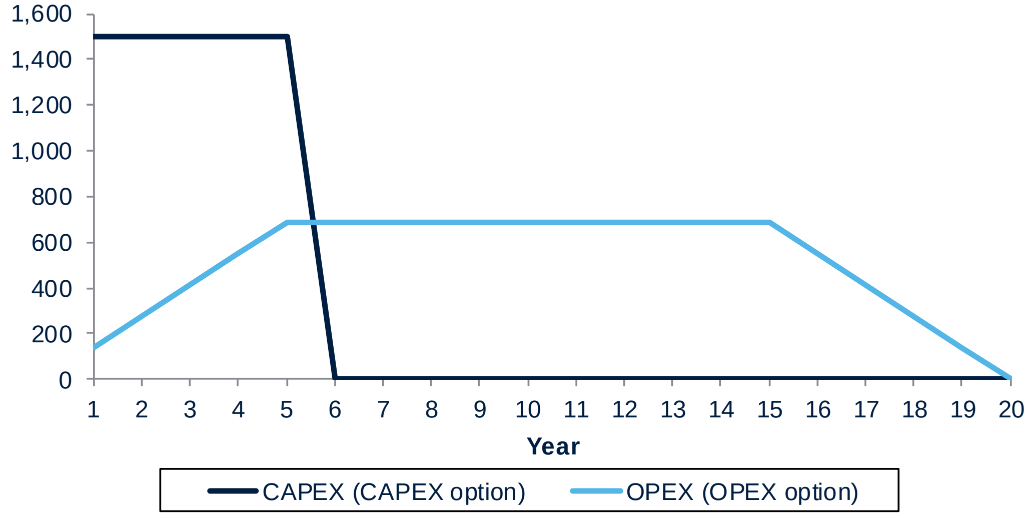
The following test can be used to check whether a regulatory system is technology-neutral.

- We assume two technological solutions to a network problem (for example, to relieve a network constraint), which cost exactly the same, in net-present-value (NPV) terms: one relies on CAPEX and the other on OPEX.
- These two network solutions are then put through (i) standard ARegV, and (ii) ARegV with the FOCS, respectively. Costs, allowed revenues and profit are calculated. The resulting discounted profits of different network solutions under different regulatory regimes are then compared.
- If the CAPEX and the OPEX options lead to similar profits, the regulatory system would be technology-neutral. If, however, the regulated company is better off when it chooses, say, the CAPEX solution, even though the two solutions actually cost the same overall, there would be a technological bias created by the regulatory treatment of costs.

CAPEX and OPEX network solutions that are NPV-equal

Figure 3.2 shows the cost profile of a CAPEX solution compared to an OPEX one. The CAPEX solution involves a five-year investment programme in order to have a solution for 20 years. For the OPEX equivalent of the CAPEX solution, we assume that the OPEX is incurred in proportion to the annual capital costs of the CAPEX solution. The OPEX solution means that costs are spread out and are incurred almost continously. We have calibrated the OPEX solution such that the discounted costs are exactly equal to the CAPEX solution. (The NPV of the costs of the CAPEX solution = the NPV of the costs of the OPEX solution = around 6,500). We assume that both options solve the network problem equally well.

Figure 3.2 Net present value expenditure profile—equivalent CAPEX and OPEX solution (in any monetary unit)



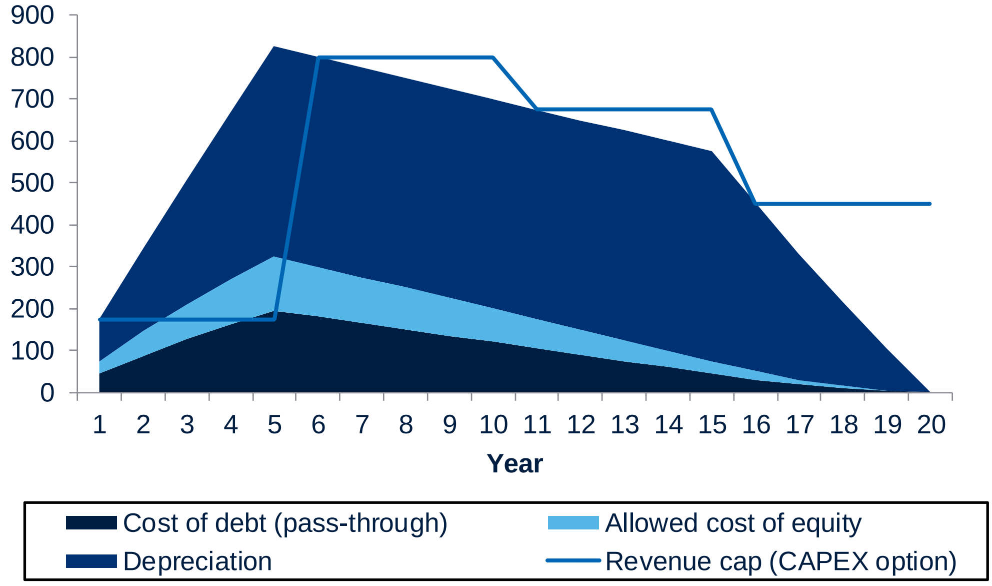
Note: The regulatory period is five years. To avoid any base-year effects, we have an investment programme that lasts throughout the five years of the regulatory period, as well as OPEX ramping up and down for five years. For simplicity, we set the snapshot year to be year 1 of the regulatory period.

Source: Oxera.

Revenue cap arising from CAPEX and OPEX under ARegV

Figure 3.3 below shows how the expenditure of the CAPEX solution would translate into allowed regulatory costs and, in five-year intervals, into the revenue cap. For simplicity, we abstract from many of the other ARegV components, such as productivity factors and inflation.

Figure 3.3 Regulatory costs and allowed revenues of CAPEX solution under standard ARegV



Note: Assuming gearing of 40% and allowed cost of equity of 5% over the whole period.

Source: Oxera.

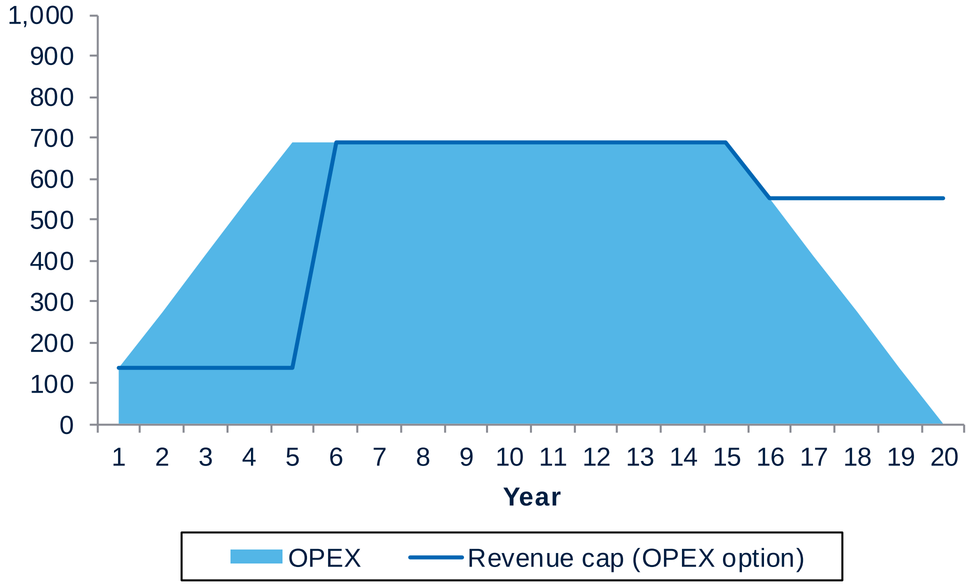
During the investment phase in the first five years, regulatory costs (depreciation, allowed cost of equity and the cost of debt) increase. The asset is then paid back ('depreciated') over 20 years. As the capital 'bound up' decreases, the allowed cost of equity decreases, as do the costs of debt. The 'plateau effect', which is typical for ARegV, can be seen clearly.

Because allowed revenues follow regulatory costs with a time lag of five years, rising costs would lead to underperformance (under-recovery) and decreasing costs would lead to outperformance (over-recovery). If there are no base-year effects,[42] the total sum of investment is recovered. Since the over-recovery takes place later than the under-recovery, this still leads to investments having a negative NPV. To overcome this and to facilitate investment, investment measures (henceforth called §23) were introduced.

§23 allows network companies to impute capital costs into the revenue cap without delay. This ensures that the NPV is not negative—i.e. that networks do invest. The resulting cash flows look similar to those in Figure 3.3, but without the delays due to allowed revenues following costs.

The OPEX solution is illustrated in Figure 3.4 below.

Figure 3.4 Regulatory costs and allowed revenues of OPEX solution under standard ARegV



Source: Oxera.

The OPEX solution looks very similar to the CAPEX solution, but is less complicated because there is only one regulatory cost category: OPEX. Again, there is a certain amount of under-recovery at the start while costs are still rising. This under-recovery is then made up for when costs start going down again (i.e. the 'plateau effect', or *Sockeleffekt*).

It is a property of the regulatory system in Germany that the NPV of changes in OPEX or CAPEX projects can differ significantly because of base-year effects.

[42] The base-year effect arises because, under ARegV, costs are set on the basis of incurred costs on a backward-looking basis only. In addition, the revenue cap is re-set only every five years. Thus, depending on when in the regulatory cycle an additional expense occurs, the effect on allowed revenues can be markedly different. The year on the basis of which the revenue cap is re-set is called a 'photo' (or snapshot, or 'base') year.

Thus, due to the time delay with which the revenue cap follows costs, the NPV of investments and changes in OPEX can vary significantly depending on when the costs finally ‘feed through’ into allowed revenues. However, we are not seeking to estimate the base-year-effect here.[43] This effect is well understood by practitioners of regulation in Germany, and, because of it, BNetzA is applying multi-year averages in its regulatory cost audit instead of only snapshot-year costs.

Profitability of CAPEX and OPEX solutions under current regulation and FOCS

Based on the costs and revenues (= revenue cap) created by the two alternative network solutions under standard ARegV and the FOCS, we have calculated the NPV of the profits arising from these solutions.

Referring to Figure 3.3 and Figure 3.4, our approach is to discount the difference between the actual costs incurred and the allowed revenues. As noted above, under both the CAPEX and the OPEX solutions, costs are first incurred and only recovered later. The resulting delay in cost recovery, which manifests itself in negative NPVs for both the CAPEX and the OPEX solutions, is a general property and potential issue of incentive regulation frameworks that rely mainly or solely on snapshot mechanisms.

To mitigate this issue, mechanisms have been introduced, such as investment measures according to §23 ARegV in Germany or the RCR projects in the Netherlands. These allow for a pass-on of investment costs into allowed revenues without any time lag. However, although investment measures and RCR projects both allow solely for the immediate recognition of CAPEX in the respective revenue caps, OPEX is considered only via (limited) lump sums under these two mechanisms.

Figure 3.5 illustrates this effect. In the first colmn of Figure 3.5, it is assumed that 50% of the costs steming from the CAPEX solution is considered via the ‘standard’ ARegV snapshot mechanism, while the other 50% is treated under the investment measure.[44] Hence, the NPV of the CAPEX solution is positive. The OPEX solution, however, features a strongly negative NPV because, as outlined above, OPEX, which is generally not covered by investment measures, is still recovered with a delay.

[43] The 2018 Oxera study looked at how the marginal incentives to save costs change depending on the regulatory system and the year in which the cost change is made. See Oxera (2018), ’Smarter Incentives for TSOs’, prepared for TenneT TSO, 11 July. That report showed that an OPEX increase in the snapshot year would be passed through immediately to consumers, while a permanent reduction in OPEX in the year directly after the base year would lead to additional profits (the discounted sum of the costs saved for the remaining length of the regulatory period—i.e. four years).
The marginal incentive to save CAPEX is more complex. For example, saving one marginal unit of CAPEX for one year (non-permanently) in the year directly after the snapshot year would lead to smaller outperformance compared to saving OPEX. This is because: (i) P&L costs go down by less than the full CAPEX saving because CAPEX enters the P&L through depreciation and capital costs only; and (ii) the reduction in CAPEX slightly reduces the allowed revenues later on.
An additional €1 spent on a CAPEX programme in the snapshot year would in theory be passed through, as would be any OPEX in the snapshot year. However, because this creates a positive plateau effect to some extent, while that CAPEX is written off, CAPEX would have a slightly positive NPV. Introducing the FOCS would equalise the incentives to control CAPEX and OPEX, however.
In the present study we start from a slightly different perspective. We do not look at the marginal incentive to ‘shave’ additional costs off a certain cost plan. Rather, we look at the incentive of whether to choose upfront a CAPEX or an OPEX solution. In doing so, we look at the difference in the NPVs of both solutions and compare them.
[44] In practice, investments are often treated partially as investment measures under §23 AregV, and partially under the standard regulatory regime, because BNetzA considers this part of the investment to be a replacement.

To summarise, the fact that investment measures according to §23 ARegV or RCR projects allow for the immediate recovery of CAPEX only, but not OPEX, results in a CAPEX bias.

As noted above, a CAPEX bias could also stem from an overestimation of the allowed cost of equity, as well as the OPEX disadvantage. Our calculations have confirmed this.

When the FOCS is introduced, all costs are treated the same, whether they are CAPEX or OPEX.

A capitalisation rate of one (CR=1), as depicted in the second column of Figure 3.5, implies that all costs are treated like CAPEX. As a result, the NPV of the CAPEX option under CR=1 is exactly the same as before, with 50% of costs being considered via the snapshot mechanism and 50% via investment measures. The NPV of the OPEX-solution is consequently the same, simply because under the FOCS with CR=1, all OPEX is now treated as if it were CAPEX.

Under the FOCS and a capitalisation rate of zero (CR=0), all costs are treated as if they were OPEX. This is shown in the fourth column of Figure 3.5. This would imply that the CAPEX and OPEX solutions have the same NPV. It would also mean that both solutions have the same negative NPV, as none of the costs are being immediately considered via investment measures, but rather solely with a delay via the snapshot mechanism.

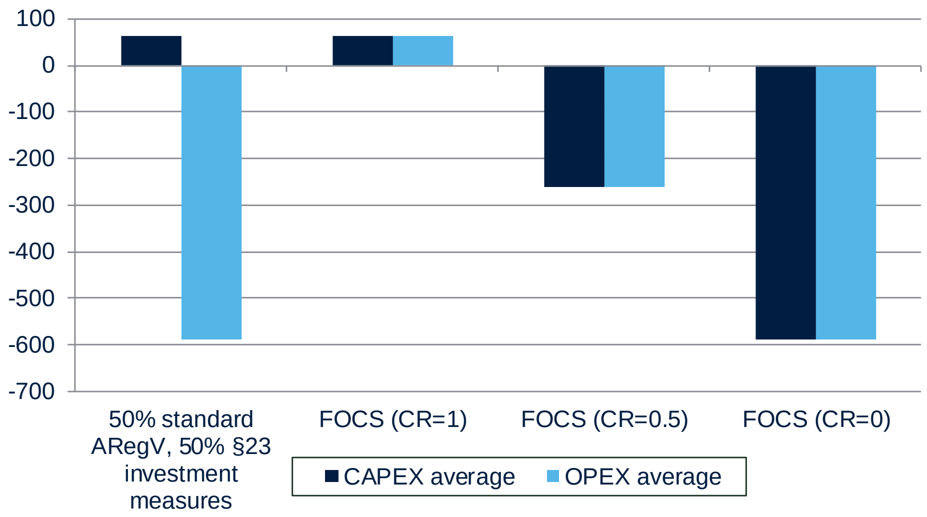
The result for CR=0.5, a capitalisation rate of 50% (as shown in the third column of Figure 3.5) follows the same logic. The sole difference is that now 50% of TOTEX is treated as CAPEX and 50% of TOTEX is treated as OPEX. While equalised through the FOCS, the NPVs of both the CAPEX and OPEX solutions are negative since 50% of TOTEX is recovered through the snapshot mechanism with a delay.

To summarise: it can be seen in Figure 3.5 that the introduction of the FOCS could lead to the profitabilty of different technical solutions being equal, and hence establishes technological neutrality of the regulatory system.

The equalising effect of the FOCS can be dominated by base-year effects.[45] As such, if there are large changes in OPEX or CAPEX year on year, particularly before or directly after the snapshot year, the spending would have to be smoothed to avoid over- or under-recovery. We understand that this is a feature of the ARegV anyway, and that it is regularly discussed in the course of the regulatory cost-checking exercise (*Kostenprüfung*).

[45] In the case of base-year effects, these NPVs can vary widely. For example, if a permanent increase in OPEX takes place exactly during the base year, the costs are passed through. Similarly, if a CAPEX programme were to take place precisely during the five years of a price control period and were to be treated like OPEX (as pay-as-you-go with a CR=0), these costs would also be passed through. If the profile of some additional spending is exactly at the level that it is passed through, these effects could be larger than other effects. That said, these effects become significant only when using relatively extreme combinations of parameters—for example, if large CAPEX programmes were to be treated as pay-as-you-go. With high and lumpy CAPEX and a low capitalisation rate, CAPEX programmes that take only a year could be completely missed in the revenue cap.

Figure 3.5 Net present value of CAPEX or OPEX solution under current regulation and the FOCS



Note: The investment is assumed to be undertaken under §23 with a 50% share of replacement expenditure (*Ersatzinvestitionen*), which is treated under the standard ARegV. To smooth out any base-year effects, each column is the average of the NPV of the CAPEX or OPEX solution for all five possible start years (year 1 to year 5).

Source: Oxera.

If we assume a CAPEX overcompensation or OPEX disadvantage, we obtain a similar result: incentives are equalised by the FOCS.

To summarise: there are several reasons why the current regulatory system has a bias towards CAPEX solutions, and the FOCS removes this bias.

3.3 Application of FOCS in Germany

In this section we demonstrate how the FOCS could be implemented in Germany without materially changing the established framework of ARegV, or the process of BNetzA's regulatory cost audit.

3.3.1 How FOCS fits into the regulatory formula

To understand which practical aspects of regulation would change through the FOCS, we start with the regulatory formula (see Figure 3.6). The formula itself is set up using TOTEX in the base (or snapshot) year. As such, it is already a TOTEX formula and does not need to be modified when the FOCS is introduced. That said, the FOCS would have an impact on the building blocks that make up TOTEX, as shown in the dark blue box in the figure.

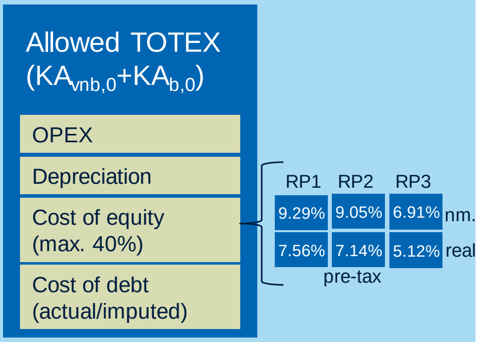
Allowed TOTEX[46] (i.e. the most important part of the revenue cap) is the result of the regulatory cost audit exercise. It splits costs into temporarily non-controllable and controllable (costs that are being reduced gradually to zero over the course of the regulatory period).

[46] In the regulatory economics literature and regulatory practice, the term TOTEX is sometimes used in differing ways. Similar to CAPEX and OPEX, TOTEX sometimes refers to expenditure. BNetzA also refers to allowed total costs based on expenditure as TOTEX.

Figure 3.6 Regulatory formula in Germany

$$EO_t = KA_{dnb,t} + (KA_{vnb,0} + (1 - V_t) \times KA_{b,0}) \times (VPI_t/VPI_0 - PF_t) \times IM_t + Q_t + (VK_t - VK_0) + S_t$$

Eo_t	revenue cap
$KA_{dnb,t}$	pass-through cost (permanently non-controllable)
$KA_{vnb,0}$	temporarily non-controllable (in base year = 0)
V_t	distribution factor
$KA_{b,0}$	controllable cost
VPI_t	consumer price index (CPI)
PF_t	general productivity factor
IM_t	investment measure
Q_t	quality factor
VK_0	volatile cost
S_t	regulatory account



Note: nm = nominal.

Source: ARegV.

Figure 3.7 shows how different building blocks would change if the FOCS were introduced.

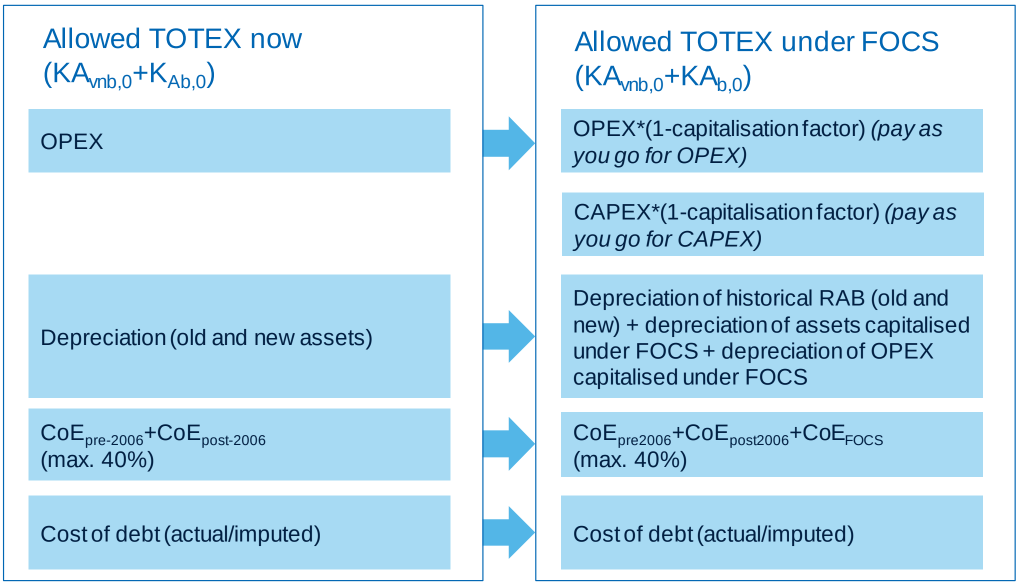
First, only part of OPEX would enter the revenue cap and the other part (OPEX*capitalisation factor) would be capitalised (added to the RAB). In exchange, part of the expenditure on capital goods would now be treated as pay-as-you-go and directly enter the revenue cap. The same capitalisation factor used for OPEX and CAPEX would make sure that both costs are treated similarly.

In terms of depreciation, we suggest that historical assets be depreciated in the RAB as originally foreseen. Changing the historical RAB would be complicated and would be unlikely to deliver advantages in terms of what the FOCS aims to achieve; namely, ensuring efficient expenditure decisions. Depreciating assets as originally foreseen has advantages in terms of regulatory certainty as well.

Under the proposals, there would be two new sources of depreciation:

- the depreciation of assets capitalised under the FOCS. Compared to the depreciation of historical assets, these would be depreciated at a rate that is uniform across all asset classes (including capitalised OPEX). The part of the original investment that was not capitalised but directly put into the revenue cap as pay-as-you-go would not be depreciated;
- capitalised OPEX (which did not enter the revenue cap directly as pay-as-you-go) would be now depreciated as well.

Figure 3.7 Changes in revenue cap building blocks under the FOCS



Source: ARegV, Oxera.

In Germany, the cost of equity is split, with a real cost of equity applied to assets dating from before 2006 and a nominal cost of equity applied to assets dating after 2006. Because the FOCS would be based on historical asset values, the nominal cost of equity is the rate to be used for assets and OPEX capitalised under that system. The 40% rule, which stipulates that only a maximum of 40% of the equity relative to total capital will receive the allowed regulated cost of equity, could be left in place (see Appendix A1).

The cost of debt in the snapshot year is simply the actual cost of debt in the statutory accounts.

BNetzA's regulatory cost audit (*Kostenprüfung*) is undertaken based on the costs that the TSO incurs in the base year, using the statutory accounts (P&L, balance sheet and asset register). According to BNetzA, this has the advantage that the input into its work is already standardised and checked by auditors.[47] How this regulatory cost-checking exercise would change under the FOCS is described in more detail in Appendix A1.

The two efficiency targets used in German regulation (individual efficiency, Xind, and sectoral productivity, Xgen) do not differentiate or discriminate between CAPEX and OPEX. The introduction of the FOCS will thus not induce any changes in how these measures are being considered when determining a TSO's allowed revenues.(see section 3.3.6 and the first paragraphs of section 3.2). However, the data underlying the calculation of Xind and Xgen might be affected, for example because the establishment of technological neutrality is likely (dynamically and increasingly) to result in the TSO taking more efficient decisions. We discuss the implications of this below, together with some options in Appendix A2.

3.4 Practical numerical example

In what follows, we run through a numerical example that illustrates the potential effect of the FOCS on the revenue cap (network tariffs) and the RAB. At the same time, this example clarifies how the FOCS works. We then look at

[47] Bundesnetzagentur (2017), 'Ermittlung der Netzkosten', 21 March.

how the capitalisation rate and the asset life of the RAB arising from the FOCS could be set by referring to the approach used in the UK and providing some example calculations.

Table 3.1 sets out the parameters used in our example. The leftmost column contains the spending in a certain year—say, 2019. Total spending is at about €2.8bn, with expenditure on capital goods at about 35%. Our example abstracts from regulatory periods and efficiency factors.

Table 3.1 Cost translation into allowed revenue under standard ARegV and the FOCS: a numerical example

	Spending (€m)	Allowed revenue (€m)	
		Standard ARegV	FOCS
OPEX	1,822	1,822	1,183
comment		*All OPEX enters allowed revenue*	*35.07% of OPEX is capitalised*
CAPEX	984	0	639
		All CAPEX is capitalised	*35.07% of CAPEX is capitalised*
Regulatory depreciation plus financing cost of existing RAB		363	363
Regulatory depreciation plus financing cost of new RAB		115	115
Total cost	2,806		
Revenue cap		2,300	2,300
CAPEX share = capitalisation rate	35.07%		

Note: Assumed economic lifetime of assets of 15 years; allowed regulatory rate of return of 5%.

Source: Oxera.

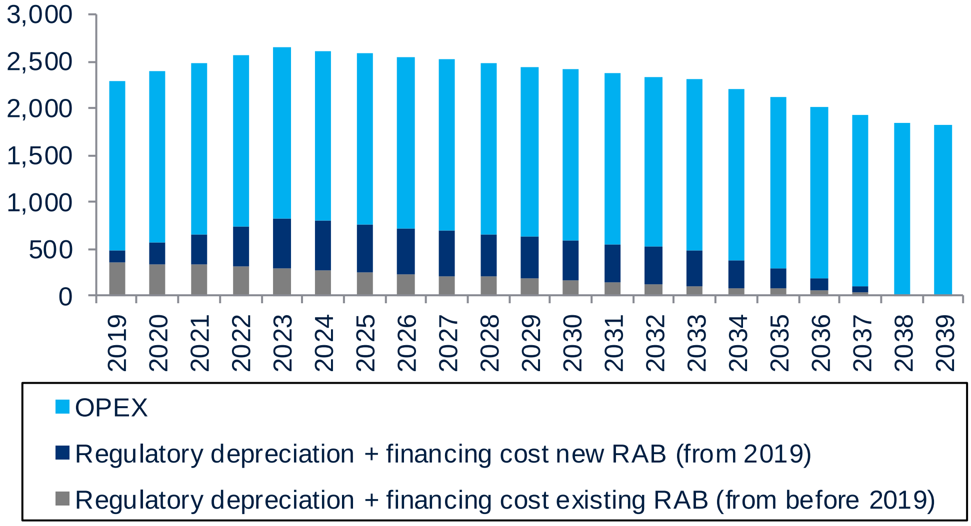
Under standard ARegV, this would translate into a revenue cap of about €2.3bn. Whereas OPEX enters the revenue cap immediately, CAPEX is capitalised and would lead to regulatory depreciation plus financing cost of €115m in that year. Existing assets capitalised at some point earlier would lead to additional regulatory depreciation, plus financing cost of €363m.

Under the FOCS, the way in which costs translate into allowed revenues would be modified. We set the capitalisation rate to 35% (similar to the CAPEX share in spending). This means that 65% of OPEX (€1,183m) and 65% of CAPEX (€639m) would directly enter the revenue cap as pay-as-you-go. The rest would be capitalised. Because the capitalisation rate is equal to the CAPEX share (e.g. the share of total spending that was capitalised before), the regulatory depreciation plus financing costs of the new RAB would be exactly the same as before. The only difference is that regulatory depreciation would now consist of depreciation of capitalised CAPEX ***and*** depreciation of capitalised OPEX.

As noted above, the existing RAB could simply be depreciated as originally foreseen.

Figure 3.8 shows how allowed revenues under standard ARegV would develop in the long run, assuming that OPEX stays at €1.8bn and the investment programme continues for another five years. Assets from before 2019 would simply be written off. Depreciation and financing costs arising from post-2019 RAB would rise until the investment programme is over, and decline from then onwards. The corresponding development of the RAB can be seen in A3.1 in Appendix A3.

Figure 3.8 Development of allowed revenues under standard ARegV (in €m)



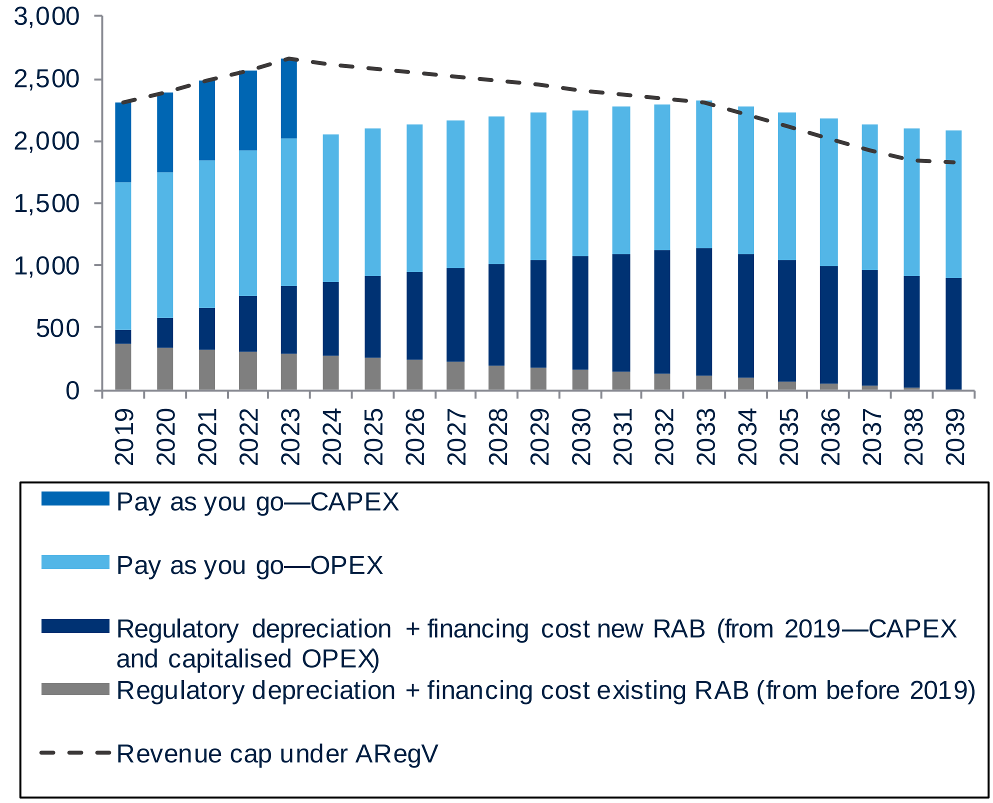
Source: Oxera.

Figure 3.9 shows how the same profile of spending (ongoing €1.8bn of OPEX and investment programme for ten years) would translate into allowed revenues under the FOCS.

Until 2023, when the investment programme of our example ends, the revenue cap would be exactly the same as under standard ARegV. Pay-as-you-go OPEX would be reduced, but as a result some CAPEX would become pay-as-you-go. Because the capitalisation ratio is equal to the CAPEX share before, the total amount being capitalised and the total amount going into the allowed revenues would stay the same (the same principle as in Table 3.1).

Assets from before 2019 would be depreciated as originally foreseen, so the grey bars at the lower end of the chart are the same in both figures.

Figure 3.9 Development of allowed revenues under the FOCS (with CR = actual CAPEX share) (€m)



Source: Oxera.

After the assumed end of the investment programme in 2023, additional properties of the FOCS system become visible. The capitalisation ratio stays at 35%, which means that 35% of OPEX is still capitalised (shifted into the future), whereas CAPEX has stopped and hence no CAPEX is capitalised. This means that, relative to what would happen under standard ARegV, the total revenue cap is reduced. To illustrate this, the dotted grey line shows what the revenue cap under ARegV would be.

In practice, investments would not drop to zero so quickly. Moreover, the capitalisation ratio is likely to be lowered to match the CAPEX share more closely, so the effect would be much less pronounced. Nevertheless, this example is useful in illustrating the properties of the FOCS.

Because OPEX continues to be capitalised, the RAB, and with it the regulatory depreciation and financing costs, would rise relative to standard ARegV (see the dotted grey line at the end of the period shown) until they reach a steady state. At this point, the newly capitalised OPEX that is being added to the RAB would be equal to the capitalised OPEX leaving the RAB, because it is written off. The corresponding RAB can be seen in A3.2 in Appendix A3.

Three conclusions can be drawn from this relatively simple numerical example.

- The introduction of the FOCS would not necessarily lead to large changes in tariffs or other payment streams, but to technological neutrality, and hence costs savings in the long run.

- A capitalisation rate that is relatively close to the CAPEX share that companies already have could help to avoid sudden changes in allowed revenues/tariffs.
- The FOCS would materially change tariffs and allowed revenues in future only if the share of CAPEX became materially different from the capitalisation rate—for example, because of a sudden drop in CAPEX (as in our example after 2023).

The main effect of the FOCS would be to make the regulatory system technology-neutral, which should lead to better investment decisions and lower overall costs in the future.

3.5 How to set the capitalisation rate and depreciation period

When a TOTEX regime was introduced in the UK, companies were allowed to suggest their own capitalisation rates when they submitted their business plans to the regulator. (Capitalisation rates were allowed to differ by company.)[48]

Ofgem accepted most of these proposals. It is likely that the companies suggested capitalisation rates close to their CAPEX share in order to minimise any financeability issues. This is an approach that could be followed in Germany and the Netherlands, at least for the TSOs.

An additional advantage of having capitalisation rates that closely resemble CAPEX shares is that companies would be less likely to run into financeability problems that might arise when they have to defer and finance large amounts of OPEX. (See year 2024 in our example above.)

The TSOs in the UK also used differing capitalisation rate for different parts of the business. For example, the transmission operation part of National Grid started with a capitalisation ratio of 85% in RIIO-1. The system operation part started with a capitalisation ratio of 27.9%.

This approach has advantages and disadvantages. On the plus side, it allows the capitalisation rate of different parts of the business to match the actual CAPEX share more closely. This could be particularly important when comparing the system operation part, which has high OPEX, and the transmission operation part, which has high CAPEX.

However, there is a minus side to this as well. One of the main advantages of the FOCS is that all costs are treated equally. Thus, the regulator does not need to negotiate with the regulated company how costs should be classified, and technological neutrality is hardwired into the regulatory system. Using different capitalisation rates for different parts of the business would compromise this advantage, at least to an extent. This is because it might give companies the incentive to shift costs between the areas if they consider this to be advantageous.

Another question is how to set the depreciation time for the RAB arising from the FOCS. In the UK, depreciation times were a matter of negotiation between Ofgem and companies. When RPI - X was introduced, relatively short depreciation periods of approximately 20 years were used in order to support financeability.[49] With the introduction of RIIO, new assets were given a depreciation time of 45 years, taking into account technical life, expected future

[48] Referred to as the 'fast money' and 'slow money' approach, within the bundle of reforms called RIIO.
[49] Ofgem (2004), 'Electricity Distribution Price Control Review', November.

electricity usage and other future developments.[50] To ensure financeability, these longer depreciation times were introduced with a transitional period of eight years.

For Germany and the Netherlands, a pragmatic solution would be to use the average lifetime of the costs capitalised for the depreciation of these costs. The advantage would be that this would lead to only minimal changes in terms of the speed of asset depreciation, and hence small changes in financing cash flows. The established depreciation times set by ARegV can be used as a basis for calculating these average depreciation times.

[50] Ofgem (2011), 'Decision on strategy for the next transmission and gas distribution price controls - RIIO-T1 and GD1 Financial issues', 31 March.

4 Conclusion

This report is a follow-up to Oxera's report on smarter incentives for European TSOs. It develops further some of the regulatory elements proposed in Oxera's first report,[51] with aim to align the economic incentives of the TSOs to achieve greater socioeconomic welfare.

Output-based incentives

The 2018 study identified several areas where output-based incentives could be introduced to align more closely the roles that the TSOs are expected to perform with the economic incentives to which they are exposed.

One aspect that was developed further as part of the present study is market facilitation. This report presents an empirical analysis of the welfare gains from cross-border electricity trade based on hourly day-ahead bid curves in Germany and the Netherlands. These welfare gains then need to be compared to the redispatch (and counter-trading) costs of making cross-border capacity available.[52]

The proposed output-based approach would link the welfare created through cross-border trade to the financial incentives for the TSOs, creating an incentive for the TSOs to provide the amount of cross-border capacity that is socially optimal (which is likely to vary from hour to hour). This would be an alternative to fixed rules, such as the 70% target recently introduced in European regulation. Our analysis suggests that, because the socially optimal amount of capacity varies every hour, the current 70% rule is unlikely to be ideal in terms of maximising welfare.

In addition, we consider a proposal to incentivise RES-infeed in a more flexible way than the current fixed rules in Germany. Pricing RES curtailment in a way that captures the associated costs and CO_2 savings would allow the TSOs to internalise the trade-off between increased costs and decreased CO_2 emissions.

Fixed OPEX/CAPEX share

This report also further develops the FOCS approach, which aims to balance the incentives for the deployment of investment and operational measures. This is done by treating all costs, be they CAPEX or OPEX, the same. Specifically, this is done by capitalising a fixed proportion of all expenditure, regardless of whether it is CAPEX or OPEX. In this study, we demonstrate the need for such an approach by showing that the ARegV system in Germany is likely to have a CAPEX bias and that introducing the FOCS could remove this bias.

We provide practical examples of how the FOCS could fit together with other elements of the German incentive regulation. It seems likely that such an approach can be used in the Netherlands as well. For the TOTEX capitalisation rate, we propose a practical approach of setting it close to the actual share of companies' CAPEX.

[51] Oxera (2018), 'Smarter Incentives for TSOs', July.
[52] Owing to data availability, it was not possible to calculate the costs of making cross-border capacity available.

A1 Effect on regulatory cost audit and accounting in Germany

BNetzA's regulatory cost audit (*Kostenprüfung*) is undertaken in every base year using the statutory accounts (P&L, balance sheet and asset register) of TSOs. According to BNetzA, this has the advantage that the input into its work is already standardised and checked by auditors.[53]

Statutory accounts are transferred into regulatory accounts, which form the basis for the allowed revenues. Furthermore, the regulatory cost audit would remove costs that are not attributable to network operations, or that are specific to the base year only.

There are three main parts to the audit:

- calculation of the amount of regulatory equity (*kalkulatorisches Eigenkapital*). This forms the basis for the cost of equity;
- the regulatory asset register, which gives the current book value of assets and regulatory depreciation (*kalkulatorische Abschreibung*);
- calculation of total regulatory costs (*Gesamtkostenblatt*). This forms the basis for calculating the total costs to be used in the efficiency benchmarking and for the revenue cap in the snapshot year.

In what follows, we briefly describe these three parts of the audit and how they would change if the FOCS were introduced.

Calculation of regulatory equity value (*kalkulatorisches Eigenkapital*)

The allowed regulatory return on equity is not calculated using the value of equity in the statutory accounts, but as set out in.[54]

Table A1.1 Calculation of regulatory equity value

+	Regulatory asset values	Because the regulatory and statutory depreciation periods differ, the regulatory asset values are used (*Alt- und Neuanlagen zu kalkulatorischen Restbuchwerten*)
-	Assets not necessary for regulated business	Only assets deemed necessary for the regulated business can count towards the regulatory equity value (*Korrektur um Bilanzwerte der Finanzanlagen und des Umlaufvermögens, aktive Rechnungsabgrenzungsposten = betriebsnotwendiges Vermögen*)
-	Interest free capital	Capital that the network operator received interest-free and deferred income are deducted (*Abzugskapital - Rückstellungen, unverzinsliche Verbindlichkeiten aus Lieferung und Leistung, Baukostenzuschüsse und sonstige Verbindlichkeiten die zinslos zur Verfügung stehen, passive Rechnungsabgrenzunsposten*)
-	Debt	Debt is deducted
=	*Betriebsnotwendiges Eigenkapital*	The result is the regulatory equity value (*betriebsnotwendiges Eigenkapital/kalkulatorisches Eigenkapital*)

Source: 'Erhebungsbogen der Kostendaten für ÜNB'.

[53] Bundesnetzagentur (2017), 'Ermittlung der Netzkosten', 21 March.
[54] 'Erhebungsbogen der Kostendaten für ÜNB'.

If the FOCS were introduced, this method could be left in place unchanged. However, the regulatory asset register would look different because it would contain the share of TOTEX that is capitalised.

Regulatory asset register (*kalkulatorische Berechnungen zu Anlagen*)

The depreciation used in the statutory accounts differs from that used in the regulatory accounts. This is why regulatory depreciation cannot be taken directly from the P&L, and is based on a separate calculation. The regulatory asset values that enter the regulatory equity (see above) are a result of the regulatory asset calculation as well.

In the regulatory asset calculation, two aspects would be different with FOCS relative to the current regime. First, assets invested under the FOCS will enter the regulatory equity at a value that is reduced by the part that was directly funded via pay-as-you-go. This can be achieved by deducting the pay-as-you-go part from the book values taken from the statutory accounts. Second, capitalised OPEX would now form part of regulatory equity. This could be accounted for by adding 'capitalised OPEX' as an item in the regulated asset register. In other words, a register of capitalised OPEX would have to be maintained in the regulatory asset register. Capitalised OPEX would increase the regulatory equity value and create additional regulatory depreciation, which would then be added to the regulatory total costs in the *Gesamtkostenblatt*.

Calculation of total regulatory costs (*Gesamtkostenblatt*)

Total regulatory costs are calculated as set out in Table A1.2. They form the basis for allowed revenues. Part of these costs are treated as non-influenceable costs (*dauerhaft nicht-beeinflussbare Kosten, dnbK*), a concept that could remain in place if the FOCS is introduced.

Table A1.2 Calculation of total regulatory costs

+	**OPEX after regulatory cost audit**	**From P&L, after having gone through regulatory cost audit**
-	Cost-reducing revenues	
+	Financing costs	From P&L
+	Regulatory depreciation (*kalkulatorische Abschreibung*)	From regulatory asset register
+	Regulatory cost of equity (*kalkulatorische EK-Kosten*)	From calculation of regulatory equity, using allowed cost of equity
=	Total regulated costs	

Source: Erhebungsbogen der Kostendaten für ÜNB.

Under the FOCS, the following modifications would be needed:

- capitalised OPEX must be deducted from OPEX because this expenditure should not form part of the pay-as-you-go;
- pass-through CAPEX has to be added to the total regulatory costs/allowed revenue;
- regulatory depreciation and regulatory cost of equity will enter the total regulatory costs in a modified way, as described above.

Having gone through the main elements of the regulatory cost audit, we conclude that the established system of the audit could broadly be kept in place if the FOCS were introduced.

In section 3.2.2, we use a numerical example to demonstrate that the revenue cap (network tariffs) and the RAB are unlikely to be materially higher or lower under the FOCS than under current regulation.

How would the statutory and regulatory balance sheet change under FOCS?

Having discussed how the regulatory accounts would change under the FOCS, we focus next on the impact on the balance sheet. For this, we distinguish between pay-as-you-go CAPEX and capitalised OPEX.

Pay-as-you-go CAPEX: the statutory asset register (*Anlagenverzeichnis*) could stay as it is; it would contain a list of assets in use. As noted above, when this statutory asset register is then transferred into the regulatory asset register, the assets that were already financed through pay-as-you-go would need to be subtracted. In balance sheet terms, pay-as-you-go CAPEX would be like interest-free financing. CAPEX that would normally have to be financed by debt or equity is now directly financed on a pay-as-you-go basis. The concept exists already in the form of funds received directly and interest-free from network users (*Baukostenzuschüsse*). This 'swap' of one form of financing with another is an accounting exchange on the liability side, and does not change the overall sum of the statutory balance sheet. The regulatory balance sheet (regulatory equity), on the other hand, is actually reduced by pay-as-you-go CAPEX.

Capitalised OPEX: as noted above, the statutory asset register would not change, and the regulatory asset register would need to introduce a record for capitalised OPEX. On the statutory balance sheet, capitalised OPEX would be a receivable against network users on the asset side. On the liabilities side, this would have to be balanced by some form of financing through debt and equity. This means that capitalised OPEX increases the sum of the statutory balance sheet as well as the sum of the regulatory balance sheet.

To summarise, whether the regulatory asset register (i.e. the RAB) increases relative to a scenario without the FOCS would depend on whether capitalised OPEX is larger than the pay-as-you-go CAPEX (e.g. the CAPEX that would have been capitalised before). This is the case if the capitalisation rate is larger than the share of CAPEX in total costs (the CAPEX share) previously.

The sum of the statutory balance sheet would increase upon the introduction of the FOCS. Pay-as-you-go CAPEX would still form part of the balance sheet through the statutory asset register, except that it would now be financed differently (through pay-as-you-go). Capitalised OPEX would also form part of the balance sheet because it would now represent a receivable of the network operator against network users/the regulator (and has to be financed by the network operator).

How the revenue cap (and therefore the network tariffs) may change with the introduction of the FOCS is discussed in section 3.4. However, would statutory P&L costs change as a result of the FOCS? This question is relevant for the calculation of the Törnqvist index, which is discussed in Appendix A2. Even as the sum of the balance sheet increases because of the FOCS, so does the amount of interest-free financing that the network operator receives. Thus, unless overall financing costs increase, P&L costs would not rise as long as the capitalisation ratio is equal to the CAPEX share. If the ratio were larger than the CAPEX share, P&L costs would increase relative to a scenario without the FOCS (and vice versa).

A2 Benchmarking and efficiency

Effect on individual efficiency Xind

International efficiency benchmarking exercises such as E3Grid and TCB18 rely on P&L data as well as balance sheet data, either according to IFRS or national GAAP. Such exercises also require extensive further normalisations (e.g. in terms of price levels and depreciation periods) in order to allow for any sensible comparison among the participating TSOs. International efficiency benchmarks are consequently abstracting from the features of national regulatory frameworks. The introduction of the FOCS would thus not affect the general way in which a participating TSO's data is being considered and processed in the international efficiency benchmarking exercise. Yet the fact that the FOCS ensures technological neutrality might affect a TSO's performance in the international efficiency benchmarking exercise due to improved efficiency that is due to better technology choices because of improved technological neutrality of the regulatory system.

An additional method used by BNetzA to set the Xgen is the 'reference grid analysis'. The cost of a hypothetical network is compared to actual total costs (TOTEX), in order to assess cost efficiency. Similar to the international efficiency benchmarking, accounting data is used and hence any possible effect of the FOCS could be accounted for.

Effect on sectoral productivity Xgen

Xgen is calculated using industry data from the German electricity network sector. BNetzA undertakes the estimation, based on two different methods: the Malmquist and Törnqvist approaches.

The **Törnqvist** approach uses data taken from the companies' (statutory) balance sheets. As such, a changing definition in regulatory costs would not make a (large) difference as long as the capitalisation ratio does not deviate too much from the actual CAPEX share (see Appendix A1). If the financing costs of a network operator do actually increase as a result of the FOCS—because the network operator now has to finance more OPEX compared to the pay-as-you-go CAPEX it receives—this would bias downwards the productivity measure resulting from the Törnqvist approach (towards a lower efficiency measure).[55] There are at least two ways in which this issue can be dealt with. First, financing costs should not be used in the calculation of a Törnqvist index anyway, but rather a 'measure of capital consumption'.[56] Second, if financing costs were still used in the calculation of the Törnqvist index, the distortion could be directly corrected for in the data by removing the incremental financing costs due to the FOCS.

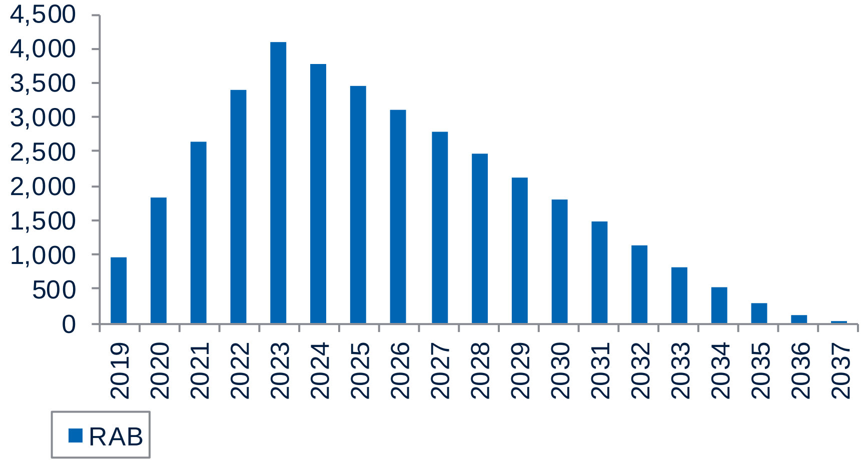
The **Malmquist** approach is based on the data used in the efficiency benchmarking. For the TSOs, the efficiency benchmarking is international, whereas for the DSOs it is national. Since Xgen measures the change in overall industry productivity between the efficiency benchmarking exercises, a change in the definition of TOTEX between periods would distort the Xgen measure. For TSOs, this means that the possible effect of the FOCS on

[55] Changes in regulatory depreciation periods due to the FOCS would not have a direct effect on the Törnqvist index because the index uses P&L data, which is based on the depreciation periods used in statutory accounting.
[56] Oxera (2018), 'Untersuchung der Törnqvist-Methode zur Ermittlung des Xgen-Strom für die dritte Regulierungsperiode; Ein Kurzgutachten für den BDEW vor dem Hintergrund des Festlegungsentwurfs der BNetzA (BK4-18-056) (Konsultation zum Xgen-Strom)', 9 November, section 13.

statutory account figures described in the paragraph above should be taken into account.

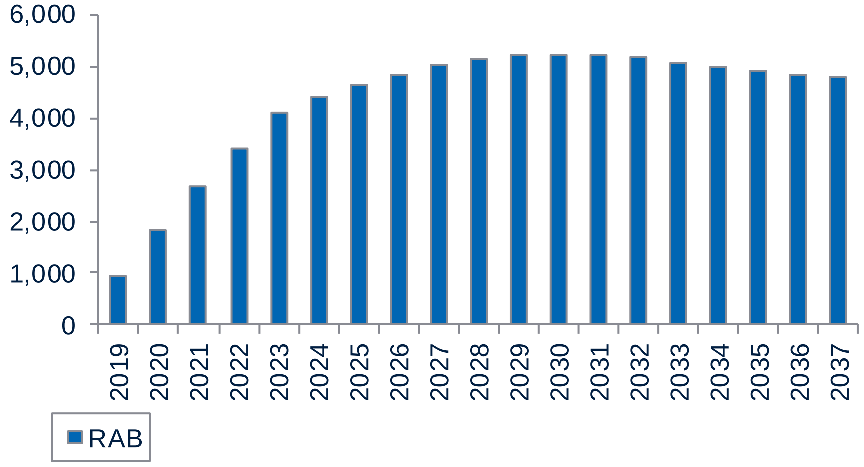
A3 Figures

Figure A3.1 Development of RAB in numerical example—standard ARegV



Source: Oxera.

Figure A3.2 Development of RAB in numerical example— FOCS



Source: Oxera.

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