frontier economics

Trends in electricity distribution network regulation in North West Europe

A REPORT PREPARED FOR ENERGY NORWAY

August 2012

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Executive Summary

This report by Frontier Economics has been commissioned by Energy Norway. It provides an evaluation of the approach to the regulation of electricity distribution networks in Norway, as compared to the approach adopted in a number of other jurisdictions in Europe. Energy Norway has asked Frontier Economics to consider how other regulators in Europe are adapting their approach to regulation to ensure that the networks are incentivised to be efficient and, also, to respond to the need for new investment in their networks. This will assist Energy Norway and its members in developing its strategy with the regulator as part of the next regulatory review.

In this context, this report draws out the key lessons and evolving trends in network regulation in Germany, Austria, Great Britain and the Netherlands, and suggests how these might be applied in the Norwegian context.

From our discussion with the Energy Norway group members, we have identified five key issues and concerns with regulation in Norway.

- **First, costs based on historic book values** do not reflect the current economic value of their assets well. This is likely to result in an overestimation of efficiency scores in old networks and underestimation in new networks. Efficiency scores are likely to be biased by the stage of the network in the investment cycle.

- **Second, costs in the DEA benchmarking are based on a one-year reference period,** and are sensitive to the cost variations from one year to the next. Large investments in a particular year are likely to have a large impact on the efficiency scores of the companies.

- **Third, there are issues with the approach to benchmarking,** including the complexity of the DEA model, errors associated with the efficiency assessment, and the mechanistic application of efficiency scores to determine the final revenue cap.

- **Fourth, there are concerns with the regional grid model,** including the treatment of large lumpy investments, and a need to assess the credibility of approaches to regulate the regional grid.

- **Finally, there is a need for greater investment and innovation incentives in general**, given the requirement for large-scale network investments going forward.

Below, we summarise the lessons that can be learnt from the countries in our case studies, and our key recommendations to address each of these issues.

Issue 1: Estimating capital costs using accounting values

The capital costs used to estimate annual allowed revenues in Norway are based on historic book values. As historic book values do not reflect the current economic value of the assets in an appropriate way, they may distort the efficiency scores from the benchmarking analysis. A concern here is that this is likely to result in an overestimation of efficiency scores in old networks and underestimation in new networks. From our case studies, we understand that this is a recognised issue across Europe, and have identified a number of different ways standardising capital costs for the benchmarking analysis. These are by:

- **Using annuities on current cost values, as in Germany**, would ensure fixed capex payments over the lifetime of the asset, reducing the impact of the investment cycle on efficiency scores. This approach has the benefit of creating more of a level-playing field for old and new networks in the benchmarking analysis, reducing the bias in favour of old networks from the use of historic costs (as in Norway). However, a drawback of this approach is that it may incentivise all networks to over-capitalise, as the adverse impact of any capex investment on efficiency scores will be averaged over a long period of time, rather than being observed in the year in which the expenditure is incurred. Therefore, if there are trade-offs between opex and capex, they may not be optimised under the use of annuities, as networks would be incentivised to replace their assets too early, rather than incurring maintenance costs, for example.

- **Using indexed historic costs (also known as current costs), as in the Netherlands**, capital costs would be based on a straight line depreciation methodology, and a WACC on residual values. This would amount to declining capital costs over the lifetime of the assets, rather than fixed capital costs in every year, as under the annuities approach. This approach has the benefit of reducing the bias in favour of old networks from the use of historic costs (as in Norway), to the extent that it adjusts for asset inflation over time, but to a lesser extent than under the annuities approach (as in Germany). Also, the incentive to spend on undesirable new capex, rather than incurring maintenance costs, would be lower under the use of indexed historic costs, relative to the annuities approach. Therefore, the trade-off between opex and capex may be better optimised under this approach, than under the use of annuities.

- **Using a 'best-of' approach, as in Germany**, is one way of testing for the impact of different ways of standardising assets. The German regulator calculates efficiency scores using two approaches. The first is based on capital costs from companies' accounts, and the second is based on standardised values (using annuities on current costs). The final company-specific efficiency factor is based on the best efficiency score from these two different model specifications. This approach would have the benefit of creating strong incentives for investments, as the revenue cap for the companies is based on the model which would afford them the highest allowed revenues. However, efficiency incentives under this approach would be low, as it could result in the over-remuneration of network costs for poor performers, and substantially reduce the discriminatory power of a benchmarking analysis and yardstick regulation.

- **Using a total expenditure (or totex) approach, as proposed in GB**, would be an alternative way of overcoming the issues associated with the accounting treatment of capex. Under this approach, the cost base is calculated as the sum of opex, capex, and repex. This is used to overcome the issues associated with the calculation of depreciation, RAB and WACC under the total cost approach (where the cost base is calculated as the sum of opex + depreciation + return) used in Norway, Germany, Austria and the Netherlands. One of the main drawbacks of the totex approach, however, is the lumpy nature of capex. Large one-off investments would have a large adverse impact on efficiency scores in the year in which they are incurred, distorting incentives for investment. To overcome this issue, Ofgem proposes to use moving averages for capital costs over a long time period. The main drawback of this approach is that it would require a fundamental overhaul of the regulatory regime as it stands in Norway, and that it has not yet been tested in actual practice in GB.

We recommend testing the impact of using different ways of standardising capital costs, as is done in Germany. As using a 'best-of' approach may result in the over-remuneration of networks, and may have adverse efficiency incentives, we discuss an alternative way of translating these different benchmarking results into a final revenue cap under issue 3, below. Although it has some attractions, the totex approach proposed by Ofgem for the next regulatory period would require a fundamental overhaul of the regulatory regime in Norway. Furthermore, given that this is also an approach that has not been tested in the GB in actual practice, we do not consider it to be suitable for Norway, as yet.

Issue 2: Using a one year reference period

NVE sets its annual allowed revenues, and conducts its annual benchmarking analysis in Norway, using costs that are based on a one-year reference period. From our discussions with Energy Norway, we understand that a drawback of this approach is that the benchmarking analysis conducted by NVE is sensitive to cost variations from one year to another due to lumpy extension and replacement investments, and also because of pension costs that are largely outside of management control.

From our case studies, we have identified a number of different options to account for the issue of cost variations from year to year, and their impact on allowed revenues.

- **By excluding pension costs from the benchmarking, as in GB**, volatility in annual revenues could be reduced, creating greater certainty for investors. Incentives for efficiency would also increase as a result of excluding costs from the benchmarking that are lumpy, and the profile of which is largely out of management control (to the extent that they depend on the age of the workforce and management decisions that may have been made in the past). On the other hand, directly passing though pension costs may create incentives for companies to implement overgenerous pension schemes for their employees. This may be argued to be the case if the management can influence the level of pension costs to a larger extent that the profile of these costs. This risk, however, could be mitigated by appropriately designing (by setting separate allowances in line with competitive benchmarks, for example) the pension adjustment that is made to the RAB.

- **By adjusting for the different accounting treatments of these pension costs in the RAB, as in Austria**, revenue allowances are less distorted by differences in the treatment of pension costs between companies. However, as this is an ex-post adjustment, efficiency incentives will still be distorted by such differences. To help facilitate comparisons on a more like-for-like basis and improve incentives for firms to be efficient, it would be more effective to adjust these costs for heterogeneous accounting policies before they enter the benchmarking analysis.

- **By normalising large one-off expenses over a longer time-period, as in Germany and Austria**, volatility in annual revenues could be reduced, creating greater certainty for investors. However, given that this approach is not governed by any defined rules, and is often based on the discretion of the regulator, it is associated with a large degree of regulatory risk and uncertainty.

- **By using long-term moving averages, as in GB,** Ofgem reduces the adverse impact of large, one-off capex investments on efficiency scores in the year in which they are incurred. This approach reduces the volatility in annual revenues, creating greater certainty for investors. However, as with the normalisation of costs in Germany and Austria, a drawback of this approach is the "lagged inefficiency" effect on revenue caps in any year.

We consider two broad types of approaches to be applicable for Norway. First is the exclusion of expenses that are either lumpy or outside of management control from the efficiency benchmarking, provided that these expenses are appropriately adjusted for in the RAB. Second is the use of long-term averages, provided that there are explicit rules to govern which costs are normalised, and under what circumstances. However, as there are tradeoffs associated with both these options, they would need to be implemented with caution. Furthermore, we suggest that any costs that are subject to heterogeneous accounting policies be adjusted for before they enter the benchmarking analysis.

Issue 3: Issues with DEA

From our discussion with the group, we understand that there are a number of issues with NVE's benchmarking analysis, including the complexity of the DEA model, errors associated with the efficiency assessment, and the mechanistic application of efficiency scores to determine the final revenue cap.

We have identified a number of different options to improve NVE's benchmarking analysis from our case studies.

- **By reducing the number of outputs in the DEA modelling, as in Germany**, and moving these to stage two of the regression analysis, NVE could lower the overestimation of efficiency scores associated with the large number of explanatory variables in DEA, and enable statistical testing.

- **By adopting a toolkit approach, as in GB**, NVE could sense-check its DEA modelling results with a number of other different modelling techniques including OLS, unit-cost analysis, and SFA. The resulting efficiency scores need not be mechanistically translated into revenue caps, but, could instead be subject to a degree of regulatory judgement. In GB, revenue caps are determined by a detailed analysis of the extent to which companies' business plans are 'well-justified'. However, this approach would be intensive in terms of regulatory input, which would be potentially infeasible in a system with a large number of DSOs.

- **By adopting a light-touch approach, as the Netherlands, NVE could** improve its model transparency, and reduce its model complexity. However, there is the risk that the large number of differences between the 150 companies would be missed. This could result in the need to be more generous (potentially in an arbitrary manner) elsewhere in the settlement. We therefore do not consider this approach to be applicable to Norway.

- **By using two different modelling techniques, as in Germany and Austria,** NVE could test the sensitivity of its benchmarking results to its choice of inputs, outputs and functional form. However, there is a risk that sensitivities introduce ambiguity in the results and increase the scope for regulatory lobbying. Multiple models may also increase the level of complexity involved in the benchmarking exercise. Furthermore, the impact of this approach on incentives for efficiency and investment would depend on how these multiple model specifications are used to set the revenue caps.

- A 'best-of' approach, as in Germany, would create the strongest incentives for investments, as the revenue cap for the companies is based on the model which would give them the highest allowed revenues. However, incentives for efficiency would be low.

- A weighted average approach would provide more of a balance between efficiency and investment incentives, when compared to the 'best-of' approach. However, there may be a great deal of ambiguity in instances when the results from the two models are drastically different, which would create scope for regulatory lobbying to determine how much weight should be attached to each of the models.

- As an alternative, the regulator could also apply a filter to mechanistically use the benchmarking results only when it would be appropriate to do so. For example, the regulator could use an average of the results from the two models, except in cases where they are drastically different (when the difference between the efficiency scores is greater than 20%, for example), when greater regulatory scrutiny could be applied. A benefit of this approach is that strikes a good balance between the use of mechanistic rules (when there is confidence in the results) and the application of regulatory judgement (when the results are more ambiguous).

- **By using the outlier detection techniques, as in Germany,** including 'super-efficiencies' and peer analysis, NVE could account for errors in the DEA benchmarking. This is an easy win, as it does not require a material increase in regulatory burden. While super-efficiency analysis is already being conducted in Norway, NVE could also test the use of peer analysis.

We consider the method of translating the benchmarking results to revenue caps in GB to be relatively intensive in terms of regulatory input, and the light-touch approach in the Netherlands to be ineffective in controlling for all the differences between the networks in Norway. While these approaches have their advantages, they are potentially infeasible in a system with a large number of DSOs. Of the feasible approaches, NVE could improve its benchmarking model by statistically testing for some of the outputs that it currently includes in its DEA model, and by a greater emphasis on outlier analysis. Furthermore, we recommend the use of a complementary benchmarking technique, such as SFA, as is done in Germany and Austria, as a useful cross-check for NVE's DEA results. Finally, to translate these benchmarking scores into revenue caps, we would recommend examining the option of a filter to use mechanistically an average of the benchmarking results, only when appropriate (when the difference between the two models is less than 20%, for example).

Issue 4: Weak regional grid model

There are drawbacks associated with NVE's regional grid model in relation to large cost variations from one year to the next. While this is related to our discussion of issue 1 above, we understand from our dialogue with Energy Norway that concerns with the large lumpy investments affect the benchmarking of regional grid to a greater extent than the distribution grid.

Furthermore, like Statnett, some of the regional network companies also own transmission lines. However, while Statnett has high incentives to invest under rate of return regulation, the regional networks are regulated using a yardstick model, which provides weak investment incentives. Meeting Statnett's requirements for investing in new transmission lines is a challenge for the regional network companies under the current regional grid model.

In this context, we assess the credibility of regulating the regional grid under a framework of yardstick regulation using DEA benchmarking, and discuss some alternatives.

From the case studies, we have considered a number of options for change.

- **By using a partial costs-pass through of capital costs, as in Austria,** NVE could remove the adverse effect on revenues from lumpy investments, and create strong investment incentives. However, this approach has two drawbacks. First, it may create an incentive to over-capitalise, and trade-off opex intensive solutions for capital intensive ones. Second, it would require a significantly higher degree of regulatory scrutiny and involvement in management decisions.

- **By reducing its reliance on benchmarking, and using more discretionary power in setting the revenues,** NVE could shift to an approach that is commonly used in regulation at the transmission/distribution level in GB, and the transmission level in Germany. While investment incentives under this approach would depend on the attitude of the regulator, we would expect these to be high. However, this may come at the expense of increased lobbying and rent seeking behaviour on the part of the companies, and reduced incentives for overall cost efficiency. Moreover, given that this approach is centred on the use of a greater degree of regulatory judgement, it would require a significant degree of increase in regulatory scrutiny on behalf of NVE.

- **By retaining the framework of yardstick regulation,** NVE could still attempt to improve incentives for investment. For example, incentives for replacement expenditure in NVE's model are currently particularly low due to the lack of a corresponding output in the DEA model, for replacement costs incurred by the companies. One option to overcome this issue would be to include an appropriate output measures in the DEA benchmarking model. A measure of quality of supply would be one option. Under this approach, an increase in replacement expenditure would be accompanied by an increase in outputs, which would increase incentives to incur these costs. In theory, this approach would improve investment incentives. However, it would be challenging to find an appropriate output measure that corresponds with the replacement expenditure incurred by the companies.

As discussed above, there are strong trade-offs associated with each of these options for change. While yardstick regulation provides incentives for efficiency, it may not be effective to incentivising sufficient investments for the regional grid due to the bias associated with the lumpy nature of capital expenditure in these assets. While an output measure for replacement expenditure could be designed for NVE's current DEA model, finding an appropriate measure may be challenging in practice. On the other hand, NVE could explore the use of some degree of cost pass-through for capital costs. This would create strong investment incentives, and may encourage to companies to over-capitalise, and would require a significantly higher degree of regulatory scrutiny and involvement in management decisions. NVE's choice of approach would need to depend on the extent to which it prioritises investment incentives over efficiency incentives, as there is a clear trade-off between the two in this issue.

Issue 5: Need for innovation incentives

Driven primarily by the green agenda, there is a greater need for rewarding and incentivising capital expenditure for smart grids, and incentivising innovation and R&D funding in the future in Norway. Furthermore, we understand from our discussions with Energy Norway that there are concerns that NVE's regulatory WACC may have historically been too low to incentivise sufficient investments. In Table 7, we compare the parameters used to set the WACC in Norway, with the countries in our case studies.

Table 1. Comparison of WACC parameters for electricity distribution companies

	Norway[1]	Netherlands (2011-13)	Germany (2009-13)	Austria (2010-13)	UK (2010-15)
Market risk premium	**4%**	4% - 6%	4.55%	5%	5.25%
Asset beta	**0.35**	0.39-0.49	0.35	0.325	0.39
Debt spread	**0.75%**	1.1% -1.9%	na	0.8%	1.25%
Gearing	60%	50% - 60%	na	60%	62.5% - 65%

Source: NVE (2011), Frontier

These comparisons suggest that there may be some upside in the WACC in Norway for the coming regulatory period, when relative to the NVE (2011) figures.

In this context, we explore two ways of stimulating further investment and innovation in Norway.

- **By creating an explicit stimulus package, as in GB**, NVE, could effectively incentivise any investment that is focused on sustainable development. However, designing and operating such a fund may be quite complex in the Norwegian landscape of more than hundred network companies. On the other hand, while other elements of the price control in GB, such as the use of well-justified business plans, would also stimulate investments, they may not be applicable to Norway given that they require a significant amount of regulatory scrutiny.

- **By providing a mark-up on WACC for investments incurred by the DSOs, as in Austria and Italy**, NVE could effectively incentivise any type of investment. A benefit of this approach is that it is direct and simple way of incentivising investment and innovation. However, it is a potentially "blunt instrument", and can be overgenerous, encouraging companies to over-invest, particularly under a regime of cost-plus regulation.

We recommend that NVE explores the use of an innovation stimulus package in Norway. As noted, while there are drawbacks associated with the use of a WACC mark-up, it can be particularly effective if targeted at certain types of investments

[1] NVE, Vil reguleringen gi tilstrekkelig avkastning?, Energidagene2011.

(investments in smart grids, for example), which the regulator may consider to be of high priority.

Further details on this discussion are available in the remained of this report.

1 Introduction

This report by Frontier Economics has been commissioned by Energy Norway. It provides an evaluation of the approach to the regulation of electricity distribution networks in Norway, as compared to the approach adopted in a number of other jurisdictions in Europe.

While the regime based on yardstick regulation is considered to have worked relatively well in Norway, this report analyses how the regulatory framework can be improved to enable network companies to deliver the requirements for large scale network investment going forward. Driven predominantly by the green agenda, the EU has estimated that €200bn of investment is required in transmission and distribution networks over this decade. It is in this context that Energy Norway has asked Frontier Economics to consider how other regulators in Europe are adapting their approach to regulation to ensure that the networks are incentivised to be efficient and, also, respond to the need for new investment in their networks. This will assist Energy Norway and its members in developing its strategy with the regulator as part of the next regulatory review.

In this context, this report draws out the key lessons and evolving trends in network regulation in Great Britain, Austria Germany, and the Netherlands, and suggests how these might be applied in the Norwegian context.

We have divided this report into seven further chapters.

- In **chapter 2**, we describe a common set of building blocks of regulation that have emerged in Europe, and how these may differ in various jurisdictions. We use this as a framework to compare the regulatory regimes in Norway, Germany, Austria, Great Britain and the Netherlands in the remaining chapters.

- In **chapter 3**, we describe the current regulatory arrangements in Norway, and set out the key issues and concerns that can be addressed going forward.

- In **chapters 4, 5, 6, and 7** we present our survey of international trends in network regulation in Germany, Austria, Great Britain, and the Netherlands, respectively. We also draw out the key lessons that can be learnt from each of these jurisdictions at the end of each chapter.

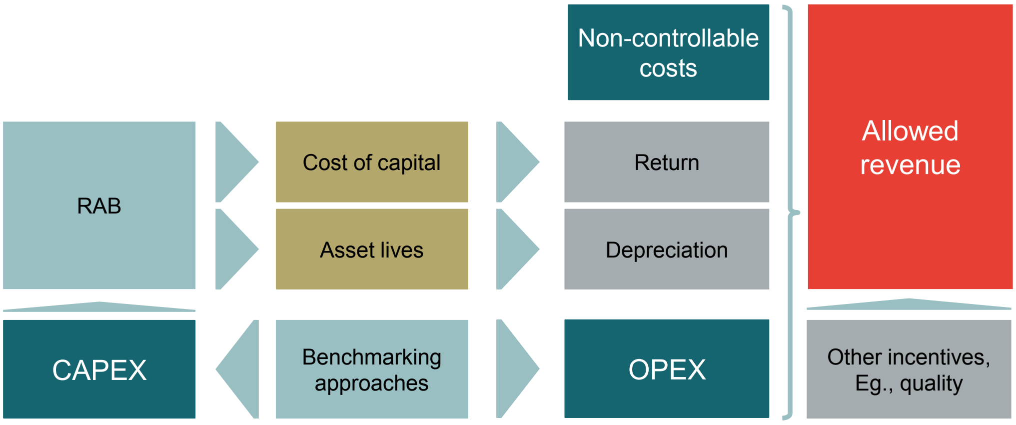
In chapter 8, we set out the implications of our study for network regulation in Norway in the future. This chapters draws out how the key issues and concerns set out in chapter 3 can be addressed by the lessons from other jurisdictions presented in chapters 4 to 7.

2 Building blocks of regulatory regimes

In this chapter, we provide an overview of a common set of building blocks of regulation that have emerged in Europe. We use this set of building blocks to describe and compare how network regulation has worked in Norway, Germany, Austria, Great Britain, and the Netherlands in the remainder of this report.

While there are clear differences among regulatory systems across Europe, it is possible to use a number of generic building blocks to describe the vast majority of systems. These building blocks are shown in Figure 1 below.

Figure 1. Principles of regulation



Source: Frontier Economics

Monopoly networks have a defined allowed regulated revenue each year. This is composed of:

- non-controllable costs, variations in which are passed through to customers as they are deemed to be outside of the control of management;
- controllable operating costs, for which networks are allocated an *ex ante* allowance representing the regulator's estimate of an efficient cost level;
- recovery of capital costs, for which networks are typically allocated an *ex ante* allowance based on the gradual repayment of capital sums efficiently invested (depreciation) and efficient financing costs arising from having to make investments ahead of receiving remuneration.

The key aspects of a regulatory regime relate to how the *ex ante* level of efficient operating costs and capital cost recovery is determined.

The regulator has much less information than the monopoly network to determine what the efficient level of operating costs or efficient level of investment might be. In determining efficient operating costs, benchmarking of networks is frequently employed. The form of the benchmarking approach, and its contribution to estimating efficient costs, is therefore a critical component of the regime.

The regulator also has to take a view as to the efficient period over which capital investments should be recovered from various generations of customers. This view is embodied in the depreciation policy. The regulator also has to take a view as to the efficient level of financing costs related to up front long-lived investments whose costs will only be recovered over time. This is embodied in the allowed weighted average cost of capital (or, where debt costs are passed through, the return on equity).

Finally, in addition to the base allowed revenue, regulatory regimes frequently include mechanisms which provide incentives for the network operators to achieve particular outcomes. For example, these may include incentives to maintain the quality of supply, as without these the network operator may simply have an incentive to beat *ex ante* allowances, even if this is achieved by allowing asset and service quality to deteriorate.

While this framework varies materially depending on the regulatory context and industry structure, we use the common set of building blocks described above to compare the regulatory regimes in Norway, Germany, Austria, Great Britain and the Netherlands in the chapters below.

3 Regulation in Norway

In this chapter, we describe the current regulatory arrangements in Norway, and set out the key issues and concerns that can be addressed going forward. These arrangements are then compared to those adopted in other jurisdictions in Europe in the remainder of this report.

3.1 Overview

Norway has in excess of 150 electricity distribution network companies that own and operate the lower voltage tiers of Norway's electricity grid. As each network is considered to be a natural monopoly, in that each company covers a separate and specific geographic area, the amount of revenue that these companies can recover from users of the network is regulated by the authorities. The approach used by the regulator to set the amount of revenue each company is allowed to recover is generically known as "yardstick regulation" or "comparative regulation". It compares the performance of one company to that of companies similar to it so that it can establish the amount of revenue that the network company should be allowed to earn whilst, at the same time, encouraging the company to be as efficient as possible in the way it operates the business.

Until 1996, companies were subject to rate of return regulation, wherein they were reimbursed with their reported costs, plus a market-determined rate of return on capital. On 1st January 1997, the Norwegian regulator introduced an incentive-based regulatory model. The basic element of the new regulatory system is that the allowed (for recovery) network costs (i.e. allowed revenue) are, to some extent, separated from actual costs. Through incentives, NVE strives to encourage network owners to reduce costs and improve efficiency. Under the new system, network owners are no longer guaranteed full cost recovery. By establishing a system whereby each network owner is allowed to receive a predetermined maximal revenue, profits will in principle be equal to the difference between allowed revenues and actual costs.

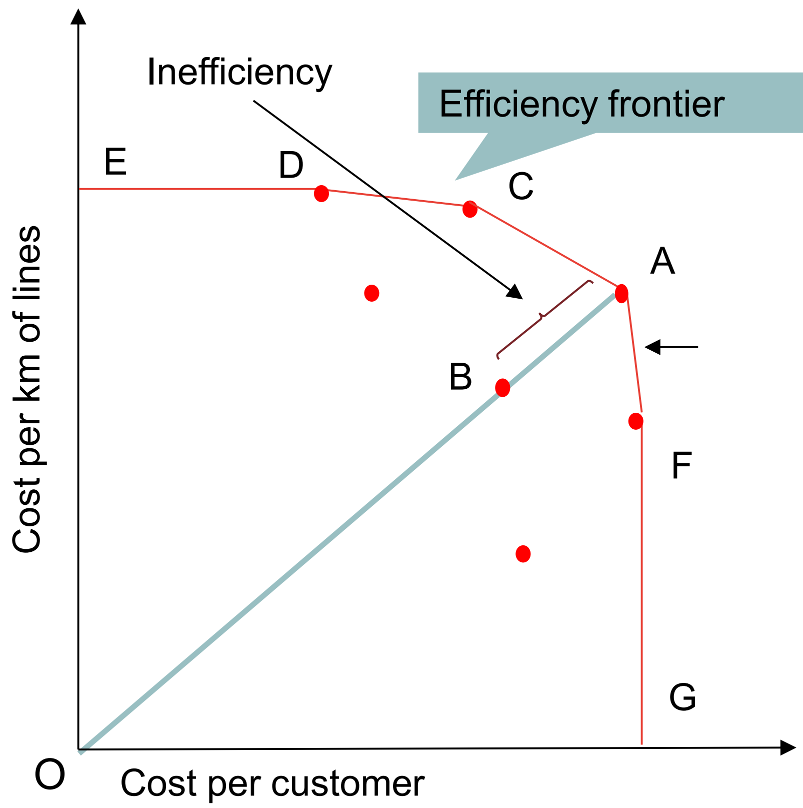
Revenue caps are set on the basis of total cost benchmarking using Data Envelopment Analysis (DEA). The model will last for at least five years, although parts of it can, in principle, be re-evaluated every year.

3.2 Extent and type of benchmarking

Revenue caps are set on the basis of total cost benchmarking using DEA. DEA is a non-parametric tool that has been used to measure the relative efficiency of electricity distribution networks in Norway and in other countries including

Germany, the Netherlands, Belgium and Austria. DEA identifies a "frontier" on which the relative performance of all utilities in the sample can be compared.

Figure 2. DEA example



Source: Frontier Economics

Figure 2 above illustrates an example of how DEA works when performance is measured using a single input (total costs), and two outputs (customer numbers and kilometres of lines). The DEA efficiency frontier in this example is given by the line joining the points E, D, C, A, F, and G. The inefficiency of company B is given by the distance from point B to A, as company A serves more kilometres of lines and customers for the same level of total costs.

Revenue caps are determined by NVE in 9 stages. These are describes in the sections 3.2.1–3.2.9 below.

3.2.1 Stage 1: calculation of DEA efficiency

The first stage towards the determination of revenue caps is the comparative benchmarking of the DSOs using DEA. The DEA analysis conducted by NVE uses only one input, total cost. The costs included in this cost base are:

- operating & maintenance costs;

- CENS (cost of energy not supplied);
- interest on capital (book values, including capital financed by investment contribution);
- depreciation; and
- cost of power losses (calculated by multiplying actual power loss with the reference price of power).

The current NVE model includes eight outputs which are included in the DEA analysis in stage one:

- subscriptions, not including vacation homes;
- subscriptions for vacation homes;
- delivered energy;
- high voltage lines;
- network stations;
- forest;
- snow; and
- wind / coast.

DEA efficiency scores are determined for each of the DSOs by benchmarking their total cost performance using the eight outputs listed above.

3.2.2 Stage 2: correction for environmental factors

The efficiency scores determined in stage one control for endogenous factors only, or those that are within management control. However, there are environmental factors outside of management control that can be adjusted for to make comparisons on a more like-for-like basis.

The second stage of NVE's analysis is designed to correct the DEA efficiency scores for three environmental factors, Interfaces, Islands and Distributed Generation (DG). This is done by regressing the efficiency scores from stage one on the environmental factors in stage two. A coefficient is calculated for each of these variables using a panel data model, as in the equation below.

$$\begin{gathered} Efficiency\ scores = \\ \beta_1 * Island\ connections \\ + \beta_2 * Transmission\ interfaces \\ + \beta_3 * Distributed\ generation \end{gathered}$$

These coefficients are then used to calculate an environmental factor correction (EFC) for each of the companies. The EFC determines how much of a disadvantage (in units of efficiency score) each grid company suffers for its amount of Islands, Interfaces and DG. This adjustment makes the efficiency scores from stage one more comparable, or so that they correspond to a common level of environment.

The next step then is to calibrate these efficiency scores.

3.2.3 Stage 3: calibrating the efficiency score

Due to the way DEA is constructed, only the companies on the efficiency frontier are 100% efficient. However, NVE uses the average efficient company as the benchmark. Therefore, NVE calibrates the results to make the representative (average efficient) company 100% efficient, which also means that on average, the companies will be able to cover their costs.

3.2.4 Stage 4: combining distribution grid with regional grid results

The three stages above describe how efficiency scores are calculated for the distribution grid. A similar process is used to calculate efficiency scores for the regional grid. In this stage, the two scores are merged into a single efficiency score for each company, weighted by the relative share of the company's costs in the regional and distribution grid.

3.2.5 Stage 5: calculating the cost base for the revenue cap

Once an efficiency score for each company has been calculated in stages 1-4, NVE determines the cost base to which these efficiency scores are applied. The first revenue cap estimates are published by the regulator prior to the year to which they apply, or before the end of year t-1. At the time, the latest available reported cost data will be for year t-2. The cost base for the revenue cap is therefore based on reported costs at t-2. This includes the following:

- operating & maintenance costs, adjusted for two years of inflation;
- CENS (cost of energy not supplied), adjusted for two years of inflation;
- depreciation;
- capital costs = RAB (t-2) * WACC; and
- cost of power losses (calculated by multiplying actual power loss with the reference price of power).

3.2.6 Stage 6: calculating the cost norm

NVE then estimates a 'cost norm' defined by the formula below.

$$Cost\ Norm_t = (Cost\ Base_t) * Efficiency_t$$

This is essentially the company's cost base[2] multiplied by its efficiency score[3], or its efficient level of costs, as estimated by NVE's model. Companies that are inefficient will have a cost base that is above their cost norm, and will not be allowed to charge their customers for the full difference between the two.

This cost norm, however, is only one component of the final revenue cap set by NVE, as described under stage 7 below.

3.2.7 Stage 7: rho – weight of norm versus actual costs

The final revenue cap set by NVE is a weighted average of the cost base from stage 6, and cost norm from stage 5, as defined by the formula below.

$$Revenue\ Cap = Cost\ Norm * \ \rho + Cost\ Base * (1 - \ \rho)$$

In other words, the final revenue cap for each company is a weighted average of its efficient level of costs, as determined by NVE, and its actual historic costs from t-2. In the current price control, the multiplier, rho (ρ) is set to 0.6. In other words, only 60% of the revenue cap is determined by the cost norm, or the efficient costs of the companies. The remaining 40% of the revenue cap is based on historic costs. This is to account for modelling errors and other differences between the grid companies that the NVE model does not take into account. These include measurement errors in the outputs, or differences in the way that costs are reported by different companies. Other errors might be due to factors that are outside management control, but are not reflected in the model. One example is that distributed generation had not been included in the model before 2010.

Once the revenue cap is set in stage 7, there are two types are errors that NVE corrects for in stages 8 and 9.

3.2.8 Stage 8: calibration correction

The first of NVE's corrections is the calibration correction associated with a rounding error in the calibration of DEA scores from stage 3.

As the DEA efficiency scores from stage 1 are rounded to two decimal places, the calibration correction from stage 3 results in a rounding error, wherein the representative (average efficient) company recovers only *roughly* 100% of its costs. The calibration correction adjusts for this error, ensuring that the industry, on

[2] Less NLR and RPC

[3] Plus NLR and RPC

average, recovers all its costs. The total effect of this calibration is relatively small (about a quarter of a percent of the total costs of the industry).

3.2.9 Stage 9: deviation correction

The final correction made by NVE in stage 9 is an ex-post deviation correction, which adjusts for the difference between reported costs in t – 2, and actual outturn costs in year t. As expected, the actual costs for year t will be different from those estimated at t - 2. This correction step reimburses the grid companies for this deviation between actual and estimated costs.

Finally, NVE also adjusts for the net present value loss from investments made in t-2 with the following formula (this has replaced the investment parameter, JP).

$$(RAB_t - RAB_{t-2}) * WACC_t + (depreciation_t - depreciation_{t-2})$$

3.3 Approach to the treatment of capital expenditure

As described in section 3.2 above, revenue caps are set on the basis of total cost benchmarking using DEA. Total costs in the cost base include an estimate of capital costs and depreciation. This section describes how NVE models these costs.

Capital costs are determined by the formula below.

$$Capital\ costs = RAB_{t-2} * WACC$$

The regulatory asset base (RAB) is based on book values (historic cost – accumulated depreciation) by the end of t-2 plus a 1% allowance for working capital. NVE defines a WACC (weighted average cost of capital) to calculate the capital costs for each company. This includes the following elements.

A Risk free rate (updated annually) is defined by a 5 year government bond. r_{NVE} = 1,14r + 2,39% where r is defined as an average rate for a 5 year government bond as it is calculated by the Norwegian central bank. This gives a risk premium of approximately 3.1 % if the interest rate is about 5 %.

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Depreciation is determined by assuming a linear profile over 30 years. As components of NVE's cost base, capital costs and depreciation influence both the 'cost norm' and final revenue caps set by NVE.

3.4 Extent of "quality regulation"

Separate quality of supply regulation was introduced by NVE in 2005, including minimum requirements regarding continuity of supply, voltage quality and customer complaints and information regarding the same issues. Companies are also obliged to collect data on short interruptions. Short interruptions were included in the DEA analysis from 2009 onwards.

Quality adjusted revenue caps were introduced in 2007. The cost of energy not supplied (CENS) is included as an element in the cost base which, in turn, influences the 'cost norm' and final revenue cap. Companies are therefore not incentivised to cut costs at the expense of quality.

Finally, there are additional incentives through guaranteed standards of performance. Whenever an outage is longer than 12 hours, a special compensation scheme applies. Moreover, consumers with more than 400MW per year are encourages to negotiate contracts themselves that also contain quality factors

3.5 Issues and concerns

While the regime based on yardstick regulation is considered to have worked relatively well in Norway, there are a number of elements that can be improved to enable network companies to deliver the requirements for large scale network investment going forward. The key issues and concerns with the Norwegian regulatory regime are discussed below.

Issues with the choice of cost base

As discussed earlier, the 'cost base' used to calculate allowed revenues are determined by reported costs in t-2. Revenue caps are updated annually using the 9 stage approach described in section 3.2. There are two main issues with NVE's choice of cost base.

- **One year reference period:** As the cost base for year t is determined by a single year of reported costs in t-2, the resulting DEA efficiency analysis is sensitive the cost variations from one year to the next. Large investments in a particular year are likely to have a large impact on the efficiency scores of the companies.

- **Differences in accounting policies:** The choice of cost base (whether it is based on book or replacement values, for example) will influence measured efficiencies. As different companies have different accounting policies, there may be large discrepancies in the way that costs are reported. Efficiency scores that are estimated on the basis of these costs may therefore be biased. Furthermore, as accounting-based costs do not reflect economic costs very well, efficiency may be overestimated in old networks and underestimated in new ones.

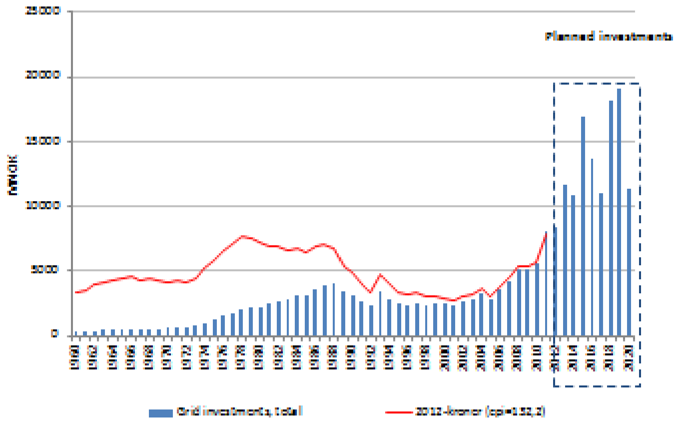
Issues with the approach to benchmarking

While DEA has been commonly used as a benchmarking technique for electricity distribution networks in Europe, its application varies significantly from country to country. There are four main issues with its application in the Norwegian context.

- **Complexity:** The DEA model in Norway includes a large number of parameters, and is subject to a large number of ex-post adjustments (including the correction for environmental factors in stage two and the calibration in stage 3).
- **Errors in efficiency assessment:** As discussed earlier, DEA efficiency scores are subject to measurement error (in the way that inputs and outputs are reported) and factors outside management control that may not be accounted for in the model.
- **Mechanistic application:** Due to these errors in efficiency assessment, only a part of the revenue cap is mechanistically based on the cost norm, or on efficient costs. The remainder of the revenue cap is based on actual historic costs. There is scope to use other techniques and sensitivity analysis to reduce or account for modelling errors, and get a more robust view of efficient costs.
- **Weak regional grid model:** As mentioned above, the DEA analysis is based on a single year of reported costs, and is therefore sensitive to large cost variations from one year to the next. This is issue is particularly relevant to the regional grid model, wherein costs are inherently lumpy.

Need for greater investment incentives

The requirement for large-scale network investment is commonplace across Europe. Driven predominantly by the green agenda, the EU has estimated that €200bn of investment is required in transmission and distribution networks over this decade. In Norway the estimated investment is Nok 110 billion until 2020 in the transmission and distribution network. In this context, there is a need for rewarding and incentivising capital expenditure (capex) for smart grids, and greater innovation and R&D funding.



Source: Norwegian Water Resources and Energy Directorate, Statnett, Statistics Norway, Energy Norway

4 Regulation in GB

In this chapter, we describe how electricity distribution networks are regulated in Great Britain. We also discuss the key lessons that can be drawn out from this regulatory regime. In chapter **Error! Reference source not found.**, we set out ow these can be applied to network regulation in Norway.

4.1 Overall approach

There are 14 distinct regulated networks in GB, which are held within 7 ownership groups. The regulatory system has been in place since privatisation in 1990. However, following a 20 year review of the system put in place at privatisation, Ofgem has proposed a major overhaul of the regime to apply from the end of the current period (2015). The review was triggered by three concerns:

- the sustainability agenda, and questions as to whether the existing regime would provide incentives for network operators to support decarbonisation in an efficient manner;
- the perceived level of efficiency, and questions as to whether after 20 years of incentive regulation, further incentives to deliver outputs that customers value were needed to ensure that companies did not "cut corners instead of costs"; and
- complexity, and concerns that the existing regime of incentives had become too complex.

The new regime is called RIIO, which stands for "Revenue equals Incentives plus Innovation plus Outputs". The rationale behind this new regime is to provide stronger incentives on network operators to deliver outputs which are valued by customers, including through greater use of innovation. It is the new regime on which we focus in this report.

The small number of operators in GB means that the regulatory system can be relatively involved, with the regulator scrutinising the proposed costs of each operator in relatively high levels of detail (although the emphasis of the regime is incentivisation rather than direct involvement of the regulator in management decisions). While benchmarking of costs is used, it is not applied mechanistically. Rather, it is one of a number of pieces of evidence which the regulator uses to determine an efficient level of revenue.

4.2 Key changes proposed under RIIO

The overall building blocks of RIIO remain the same as the RPI-X regime that was previously in place. However, there are two key structural differences between the initial and new regimes, which are described in the sections below.

4.2.1 Output focus

The new regime will explicitly link revenue to "outputs" to a greater extent than previously, with failure to deliver outputs resulting in some form of financial penalty. Ofgem describes two categories of outputs, primary outputs and secondary deliverables. Primary outputs will be defined across 6 categories, namely customer satisfaction, safety, reliability and availability, conditions for connections, environmental impact and social obligations. Ofgem's proposed measures for these outputs are described in Table 2 below.

Table 2. Ofgem's primary outputs

Output category	Ofgem measure	Objective
Customer satisfaction	1. Broad measures of customer satisfaction 2. Qualitative survey evidence	Demonstrate network performance and relate to services delivers
Safety	1. Compliance with minimum legal requirements 2. Additional safety initiatives considered to be in public interest	Demonstrate network performance and relate to services delivers
Reliability and availability	1. Customer interruptions (CI) 2. Customer minutes lost (CML) or energy not supplied (ENS)	Demonstrate network performance and relate to services delivers
Conditions for connections	1. Time to connect a generation node 2. Time to connect a demand node	Demonstrate Impact on environmental targets
Environmental impact	1. Carbon footprint of network including losses 2. Proportion of new low carbon generation 3. Other emissions 4. Visual impacts 5. Role in consumer energy efficiency	Monitor compliance with legislation
Social obligations	1. Targets for vulnerable customers, e.g. PSOs	Monitor compliance with legislation

Source: Frontier Economics

However, if price controls only targeted primary outputs, there would be an incentive to lower costs during the control itself, at the expense of measures that could help reduce costs of their delivery over the longer term. As a solution, Ofgem has proposed to consider secondary deliverables, through which it would allow spend in current period that improved primary output delivery in future periods. However, there would be a need for a well-evidenced case including a clear link between costs now and savings in the future, and stakeholder engagement, where relevant.

4.2.2 Well-justified plans

Network operators will be required to submit a detailed business plan for an 8 year period, setting out the activities they intend to carry out, the outputs for customers which they will deliver, and the revenue they will require to do this efficiently. These plans must have been developed in conjunction with stakeholders (network users, end customers etc.).

Ofgem sets out 9 criteria to determine whether a company's business plan is 'well-justified'.

- Focus on output delivery
- Consideration of secondary deliverables
- A clear and well-evidenced case for their proposals
- An open minded consideration of available options
- Link between costs and primary outputs:
- A consideration of the longer term
- Value for money
- Effective engagement with a range of stakeholders
- Working with others

A well-justified plan could potentially be "fast tracked", or the settlement agreed a year early, and "match or almost match" the plan. As such, the level of regulatory scrutiny is likely to be proportionate to the quality of a company's business plan. This creates strong incentives for the companies to engage effectively with the stakeholders and the regulator.

4.3 Determination of base revenues

Ofgem will determine the base revenues for the DNOs using a two stage approach. An initial assessment will be conducted in stage 1. Once the network companies submit their business plans to Ofgem, it will undertake an 'initial sweep' of the information to determine how to assess the expected efficient costs of delivery for each company. The level of scrutiny required in the more detailed assessment in stage 2 will depend of the assessment in stage 1.

Ofgem's initial sweep in stage 1 will be based on three streams of analysis.

- an analysis of the quality of business plan submitted by the companies. This will be assessed on the basis of the 9 criteria for well-justified business plans described in section 4.2.2.;

- a high-level analysis of past performance, of both primary outputs and secondary deliverables, and of historic costs; and
- total cost benchmarking of business plan forecasts.

The analysis above will be the starting point for assessment, and will have no mechanistic link with allowed revenues. Companies will be categorised into three groups on the basis of this initial analysis conducted in stage 1.

Table 3. Categorisation of DNOs after stage 1

Category	Level of scrutiny	Engagement with Ofgem	Outcome
Category A	Low	Potential to be "fast-tracked"	Expectation that Ofgem's assessment of primary outputs, secondary deliverables and expected efficiency costs will be close to the company's business plan proposals.
Category B	Relatively high	Engagement with Ofgem at all stages	Level of scrutiny potentially similar to what companies have experienced in review in the past.
Category C	Most intensive	Engagement with Ofgem at all stages	Ofgem may send engineering experts to consider in detail the justification that network companies have provided for their proposed asset strategies.

Source: Frontier Economics

As described in Table 3 above, companies with well-justified business plans and relatively efficient historic and forecast performance have the potential to be fast-tracked. Companies in categories B and C, on the other hand, will be subject to more intensive levels of scrutiny in stage 2, or Ofgem's detailed assessment of base revenues. Section 4.4 below describes the extent and type of benchmarking used in Ofgem's detailed assessment of the companies in categories B and C.

4.4 Extent and type of benchmarking

Ofgem intends to use a range of techniques (or a 'toolkit' approach) to assess the base revenue requirement proposed by network operators in their business plans. These include:

- total expenditure (totex) benchmarking;

- disaggregated benchmarking;
- historical trend analysis;
- unit quantity analysis;
- asset unit cost analysis;
- output unit cost analysis;
- expert review; and
- project by project review.

4.4.1 Totex benchmarking

Totex benchmarking will be used alongside other techniques as a 'directional' tool or a starting point for assessing the company's forecasts, rather than as a mechanistic means of setting allowances.

The rationale for applying totex benchmarking is to avoid the incentive for network operators to focus efficiency improvements in opex rather than capex or *vice versa*.

Ofgem has not yet provided full details on the way they intend to apply totex benchmarking. They have suggested two possible formulations of "total expenditure":

- total expenditure = opex + capex + repex; and
- total cost = opex+ depreciation + opportunity cost of capital (WACC * RAV)

Ofgem has indicated that their preference is the total expenditure approach, as it is less sensitive to the tools used to determine RAV and WACC. They suggest that a moving average of the expenditure is used to remove large annual changes in spending. They propose that panel data regressions will be estimated with a time fixed-effects model using the ordinary least squares (OLS) technique, with some costs being removed to adjust for regional and company-specific environmental factors.

4.4.2 Disaggregated benchmarking

Ofgem suggests they will continue to use disaggregated benchmarking of costs as part of the RIIO regime. Again, they have not been explicit as to how this will be undertaken. However, some insight can be gained from their previous approach, which was separate for opex and capex.

Opex

Ofgem previously undertook detailed comparative analysis across DNOs of both network operating costs (directly associated with the operation of the network, such as management of faults, inspection and maintenance, tree cutting etc.) and indirect costs (associated with support functions such as network design, stores management, call centres, corporate support functions etc.)

Ofgem's detailed opex benchmarking related these costs to a number of different drivers, associated with:

- overall network scale, such as customer numbers or network length; and
- "work" variables, such as number of faults.

Capex

Ofgem previously undertook comparative analysis across DNOs of:

- the volumes of work undertaken in relatively detailed activity categories; and
- the unit costs for different capital investment activities.

This benchmarking informed reductions to individual DNO proposals for capital investment requirements.

4.5 Approach to the treatment of capital expenditure

As part of their business plans, DNOs are required to submit estimates of the capital expenditure required to meet their commitments in terms of outputs. This is subject to review by the regulator using the techniques described above. However, once spending is approved, the DNO is remunerated for these investment needs and associated financing costs. If the DNO can meet outputs without recourse to investment, it will retain some proportion of the revenue associated with the investment as an incentive. The elements of Ofgem's approach to treating capital expenditure is described below.

4.5.1 RAB

During each price control review, Ofgem reviews the investment undertaken during the previous period. If Ofgem is comfortable that the investment was efficient, a proportion of it is allowed into the RAB. The remainder is expensed in the year it is incurred. Some proportion of opex will also be capitalised and placed into the RAB, with the remainder expensed in the year incurred. The rationale for this is to equalise incentives to avoid spending between opex and capex.

The proportion of expense which is placed into the RAB is determined by the cashflow needs of the DNO.

4.5.2 WACC

Under RIIO, the cost of debt and cost of equity will be treated separately.

The cost of debt for all companies will be based on a long-term trailing average of an index of corporate bonds. This will be updated annually within the price control, and hence movements in average debt costs are passed through to customers.

The cost of equity parameter will be assessed using the capital asset pricing model (CAPM), but sense checked using other methods including the dividend growth model (DGM) and market to asset ratios (MAR).

Incentives within the overall price control package will be calibrated to ensure that a poorly performing company will receive a low cost of equity (Ofgem previously suggested an equity return consistent with that of a debt holder).

4.5.3 Depreciation

Existing assets have an assumed depreciation lifetime of 20 years, although they are likely to have a physical life of more than 45 years. The intention under RIIO is to increase the assumed depreciation lifetime such that it better reflects the likely useful economic life, though this will need to be balanced with the cashflow requirements of the companies (as longer depreciation lifetimes implies slower recovery of capital costs and may result in cashflow constraints).

4.6 Extent of "quality regulation"

Under the existing price control, there are a number of quality related incentives for DNOs. These include:

- Guaranteed standards of service, under which DNOs must compensate customers for failing to achieve certain minimum requirements;
- Customer Interruptions (CI), under which companies receive payments or penalties based on their performance relative to a target number of interruptions (>3 min) per 100 customers; and
- Customer Minutes Lost (CML), under which companies receive payments or penalties based on their performance relative to a target number of minutes lost due to interruptions (>3 min) per customer.

There are a range of further incentive schemes under the current control, which could be interpreted as relating loosely to "quality" regulation. For example, companies are incentivised as to their peak withdrawal from the transmission system, as this in turn drives transmission network investment requirements.

Under the new RIIO framework, it is proposed that these incentives be consolidated into commitments in relation to outputs across 6 categories:

- customer satisfaction;
- safety;
- reliability and availability;
- conditions for connections;
- environmental impact; and
- social obligations

For some outputs, where quantification is possible and DNO control is relatively clear, there will be specific financial incentives (i.e. a link between outturn output levels and revenue). For others, Ofgem will review performance against targets at the next price control review and take into account underperformance when considering forward looking revenue.

4.7 Innovation incentives

Under RIIO, Ofgem has placed a major emphasis on the need for innovation by network owners, particularly given the changing role of networks required to achieve decarbonisation in the sector. There were three main drivers for the focus on innovation:

- the lack of history of innovation among networks, given the absence of need for innovation historically;
- the previous regulatory regime, under which companies did not retain any benefits from innovation which did not accrue within the 5 year price control period; and
- free-riding as a result of knowledge spillovers, where because innovation by some parties generates benefits for others, there is an incentive not to innovate.

Ofgem intends to encourage innovation in a two key ways:

- providing stronger incentives to delivering outputs more cheaply, including 8 year price control periods, and not disallowing investments that turn out to be less successful than expected; and
- providing explicit funding for innovation, through a stimulus package which funds DNOs undertaking activities from original research through to scale trialling of developed but non-commercially exploited technologies.

4.8 Key lessons

The framework of incentive regulation in the UK is designed to facilitate efficiency savings, output delivery and innovation in a stable and transparent regulatory environment. The key lessons that can be learnt from electricity distribution network regulation in the UK are described below.

- **Focus on long-term delivery**, through a longer-term (8 year) price control and through longer-term incentives to take action to respond to anticipated future demand for network services, where appropriate.
- **Emphasis on delivering outputs** rather than simply cost cutting, through a well-defined framework for primary outputs and secondary deliverables
- **A proportionate assessment of business-plans** (depending on the extent to which they are well-justified), helps increase stakeholder engagement, reduce the regulatory burden and incentivises efficient behaviour.
- **A 'toolkit' approach** helps equalise incentives (reducing the incentive for companies to adjust their plans to perform well in just one assessment), helps identify the drivers of cost savings (through the use of more disaggregate modelling), allows for a less mechanistic approach (facilitated by sensitivity analysis), and improves robustness (by cross-checking each approach by a number of others).
- **Smoothing of 'lumpy' capital expenditure** in Ofgem's total cost benchmarking (through the use of long-term moving averages) makes the modelling less sensitive to large one-off investments.
- **Stimulation of innovation** within the price control framework, and through a designated innovation stimulus package, incentivises the deployment of new technologies, and implementation of new operational processes and commercial arrangements.

The relatively small number of DNOs in GB facilitates a closer level of engagement of the companies with the regulator, and a less mechanistic approach to the determination of revenue caps. Some of the elements of the regulatory regime in the UK, therefore, (such as the proportional assessment of business plans, for example) may not be directly applicable to the Norwegian context. Nevertheless, other elements, such as the smoothing of capex, and incentives for innovation are more relevant. In chapter **Error! Reference source not found.**, e discuss how these lessons from regulation in the GB can be applied to the framework in Norway.

5 Regulation in Austria

5.1 Overall approach

The Austrian electricity market was fully liberalised in 2001. Energy-Control, the regulator for electricity and gas, was established in 2000 and is in charge of setting network tariffs.

There were two phases in the regulation of electricity networks:

- *Cost-plus regulation from 2001-2005* – which resulted in a sharp reduction in average network tariffs (average 20%); and
- *Incentive-based regulation since 2006* – there was a long discussion between companies and Energy-Control on the implementation of incentive-regulation lasting back to 2003. However, the first attempt in 2003 for switching from cost-based to incentive-based regulation failed due to the heavy resistance of the companies, but the change was then made in 2006

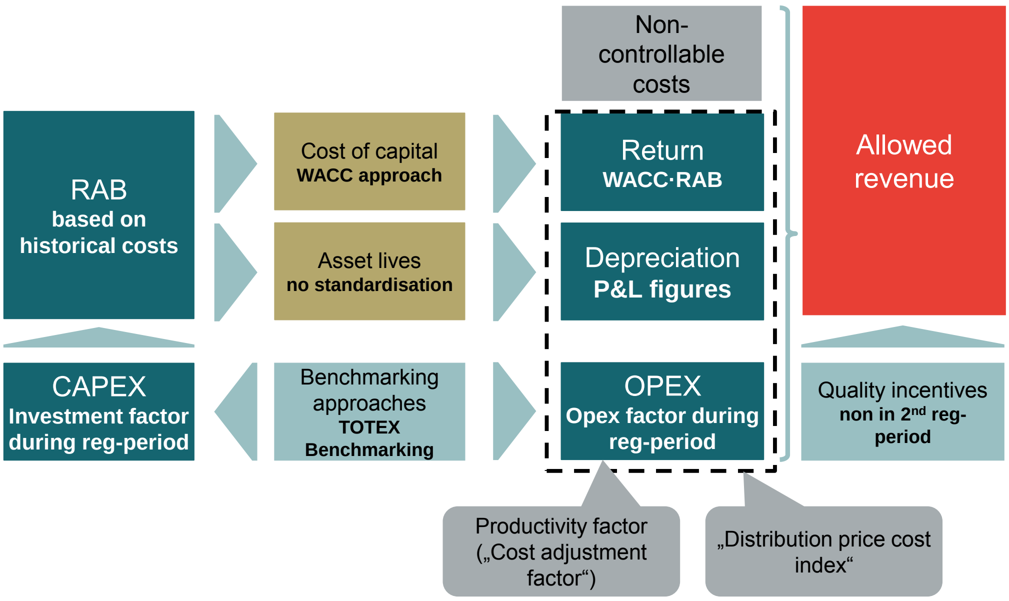
The Austrian regulatory system since 2006 is based on a revenue cap with a regulatory period of 4 years. The 1st period was from 2006-2009, and the 2nd period will last from 2010-2013. Currently, there is an ongoing discussion process between Energy-Control and the companies about the design of the 3rd regulatory period starting in 2014.

5.2 Overall ethos of the regime and building blocks

Energy-Control stated the principles for the revenue cap in the explanatory notes to the System charges order 2006, where the details of incentive regulation for the 1st regulatory period – which are also valid for the subsequent periods – are described. One important principle is the "principle of latest available data", which means that Energy-Control normally does not use forecasts or planned data from companies, when setting the allowed costs, revenues and tariffs.

This results in a t-2 time lag for costs included in the actual tariffs, which tends not be a serious problem in times of stable costs. However, during the consultation for the 2nd regulatory period, companies complained that the t-2 time lag will lead to a systematic under recovery of costs due to increasing replacement investments and investments in innovation, e.g. smart grids. Energy-Control tried to ease this problem by introducing the so called **investment factor** in the 2nd regulatory period.

Figure 3. Building blocks for 2nd regulatory period (2010-2013)



Source: Frontier Economics

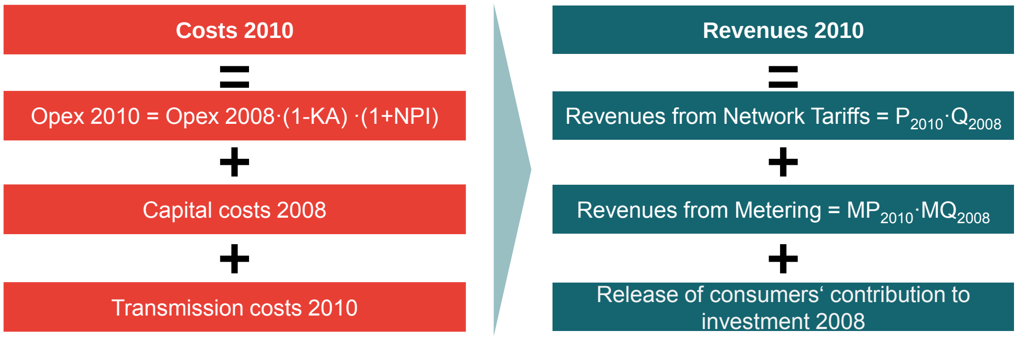
In the following we will describe how the allowed costs and revenues are derived for

- 2010 (first year); and the
- 2011-2013

in the 2nd regulatory period.

5.2.1 2nd regulatory period – Determining building block and tariffs for 2010

Figure 4. Building block for 2010



Source: Frontier Economics

The relevant **costs for 2010** consist of:

- **Opex 2010** – which are audited operating expenditures 2008 adjusted to 2010 by
  - *Cost adjustment factor* (KA)[4] – to reflect productivity improvements
  - *Distribution price cost index* (NPI)[5] – to reflect exogenous cost increases
- **Capital costs 2008** – which consist of
  - P&L depreciations 2008
  - WACC*RAB 2008 (based on historical costs) – where the WACC is based on a nominal pre-tax rate. The regulatory asset base is defined by the tangible assets minus customer contributions. Working capital is not included.
- **Transmission costs 2010** – which consist of the
  - quantity of energy from higher voltage level from 2008 multiplied at
  - 2010 transmission charges.

The network tariffs are set in such a way that costs 2010 equal **revenues 2010**:

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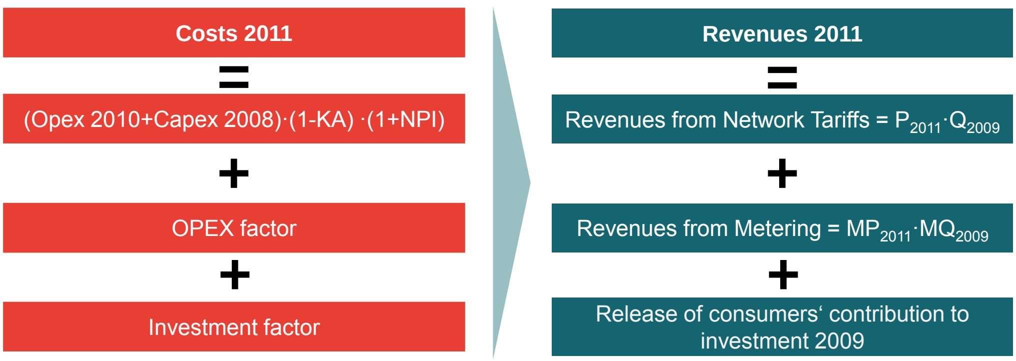
[4] See Section 5.3.1.

[5] See Section 5.4.

- **Revenues from Network Tariffs 2010** – which are based on latest available quantity data (MW, MWh) from 2008.
- **Revenues from Metering 2010** – which consist of
  - Meter tariffs from 2010 (MP_{2010}) multiplied by
  - Number of Meters in 2008 (MQ_{2008})
- **Release of consumers‘ contribution to investment 2008**

5.2.2 2nd regulatory period – Determining building block and tariffs after 2010

Figure 5. Building block after 2010



Source: Frontier Economics

The revenue side will remain similar to the one in the first year, only the relevant year changes, e.g. for tariffs 2011 quantities from 2009 are used.

The cost side starting with 2011 will face some differences to the first year:

- **Opex and capex** are now adjusted by
  - *Cost adjustment factor (KA)* (Section 5.3.1) and the
  - *Distribution price cost index (NPI)*
- **Opex factor** – which covers higher Opex during regulatory period due to change in the scale of activities;
- **Investment factor** – which covers higher capital expenditures (investments) during regulatory period due to replacement, extension and/or innovation investments.

5.3 Extent and type of benchmarking

In the following we will describe the benchmarking analysis which is used by Energy-Control to set cost targets – or productivity factor – for companies based on their costs efficiencies.

5.3.1 Cost adjustment factor on total costs

E-Control calls the productivity factor **Cost adjustment factor** (KA). Similar to the Netherlands and Germany the Cost adjustment factor is used on total costs. The factor combines two productivity improvements:

- *Frontier Shift (1.95%)*[6] – which reflects the shift of the efficiency frontier, i.e. the productivity improvement of the efficient companies;
- *Efficiency dependent firm specific productivity factor* – which reflects the catch-up to the efficiency frontier, i.e. the productivity improvement by inefficient companies to become efficient.

Energy-Control defined a catch-up period to reach the efficiency frontier of 8 years, which means that companies have to eliminate all their cost inefficiencies during two regulatory periods. However, in order not to jeopardize the financial capability of the companies Energy-Control set a minimum efficiency score by 74.8%, effectively limiting the maximum efficiency dependent productivity factor to 3.5%. By including the Frontier shift (1.95%) one gets a range from 1.95% to 5.45% for the Cost adjustment factor.

There are a few steps involved when calculating the Cost adjustment factor:

- *Preliminary Step* - calculate company's efficiency score
- *First Step* – calculate efficient costs in year 8 (including Frontier Shift)
- *Second Step* – calculate annual cost reduction for reaching efficiency frontier (including Frontier Shift) in year 8.

In order to get the efficiency scores Energy-Control undertook a benchmarking analysis in preparation of the 1st regulatory period starting in 2006 and used the results from this analysis also for the 2nd regulatory period starting in 2010.

5.3.2 Benchmarking analysis

There are different steps involved when undertaking a benchmarking analysis:

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6 Energy-Control based the level of the Frontier Shift on international examples from European regulators, including Netherlands and Norway, and international empirical studies of productivity developments for regulated electricity networks.

- defining the benchmarking technique;
- defining the costs;
- defining the outputs which describe the supply task of the network companies; and
- calculating the efficiency values for cost targets.

Benchmarking technique – two approaches used

The term "benchmarking technique" refers to mathematical models that relate individual companies' inputs and outputs, and use the resultant productivity indicators to compare their efficiency with that of other firms. A variety of algorithms can be used to estimate relative efficiency. All these models compare the efficiency of the companies studied with that of best practice firms which is usually taken as 100%. Less efficient companies rate less than 100%.

Energy-Control evaluated the advantages and disadvantages of different benchmarking techniques and decided to use:

- *Data Envelopment Analysis (DEA)* – which is a non-parametric/deterministic method; and
- *Modified Ordinary Least Squares (MOLS)* – which is a parametric/(stochastic) method.

In a first attempt 2003 Energy-Control proposed to use Stochastic Frontier Analysis (SFA) instead of MOLS, because more companies were included in the sample making SFA applicable. However, the size was reduced to 23 companies in the benchmarking analysis in preparation of the 1st regulatory period.

Energy-Control uses DEA with constant-returns-to-scale[7], as network companies are typically able to alter the scale of their operations by means of mergers, joint ventures or disposals. Inefficiencies due to suboptimal scale are thus the responsibility of the managements concerned. However, due to the functional form of the cost function Energy-Control implicitly used variable-returns-to-scale for MOLS.

Energy-Control decided not to specify a primary and secondary benchmarking technique. The reason was that due to the advantages and disadvantages of different benchmarking techniques the resulting efficiency values may be:

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7 The term "returns to scale" refers to economies of scale achieved by varying company size. While a doubling of input factors (variable costs) results in a doubling of outputs under conditions of constant returns to scale (CRS), changes in inputs and outputs are not proportionate where variable returns to scale (VRS) apply.

- too low because the use of deterministic methods means that statistical inaccuracies in the data are not corrected, and noise may therefore be interpreted as inefficiency;
- too high because the method used attaches too much weight to unique characteristics of companies.

In order to provide a fair balance between companies and customers Energy-Control decided to use a weighting of efficiency results from DEA and MOLS.

Benchmarked costs – total costs to avoid incentives for suboptimal capital intensity

Energy-Control benchmarks total costs. The use of total costs has the advantage that it does not create perverse incentives for suboptimal capital intensity as the substitution of operating by capital expenditures does not result in any change in the efficiency scores – unless it actually leads to a total cost savings.

Energy-Control made some adjustment on the benchmarking costs:

- *Exclusion of costs for network loses* – Since the determination of the system loss charges is subject to a different system the network loss costs are deducted from the costs.
- *Exclusion of metering costs* – As the metering charges are separately determined the metering costs are stripped out of the costs. E-Control used metering revenues as the relevant proxy for metering costs.
- *Correction for customer contributions* – The Austrian system operators apply different weightings to customer contributions for installation costs. This must be controlled for, as firms with lower weightings would otherwise be systematically disadvantaged. This bias is neutralised when the cost of capital is calculated by adding the customer contributions to the regulatory asset base.

E-Control did not standardise the capital costs for differences in depreciation policies between companies and used P&L depreciation for the benchmarking analysis. E-Control used this approach due to lack of company data during benchmarking analysis and the time pressure when introducing incentive-regulation in 2005.[8]

We are not aware of any plans of E-Control to use standardised capital costs in the coming benchmarking analysis for the 3rd regulatory period starting 2014. However, the relevant companies' data are now available.

8 E-Control gathered data for past investments grouped in asset categories in 2007. However, E-Control used standardised depreciation periods for the benchmarking analysis of gas distribution networks in 2008.

Defining the outputs using model network analysis

The main objective of the outputs is that they reflect the supply task of a network company. E-Control used a two-step approach when choosing the relevant outputs in their benchmarking analysis:

- *First step* – E-Control used an engineering based model network analysis to identify significant cost-drivers for the complexity of the operating environment of a network company and the functional relationship between cost-drivers and costs.
- *Second step* – In the following E-Control tested the statistical significance of the outputs derived from the model network analysis and the quality of the base model and tested additional outputs and environmental factors.

First step – model network analysis

Model network analysis reveals relationships between certain exogenous characteristics of a firm's supply task and the size of the network that would have to be built to perform it in a simplified but objective manner. The method can be used to design "model" networks for different, homogeneous supply areas by emulating typical approaches to network planning. By varying characteristics of the supply task it is possible to investigate their influence on the scale of the network assets required.

The supply task is described by the inputs:

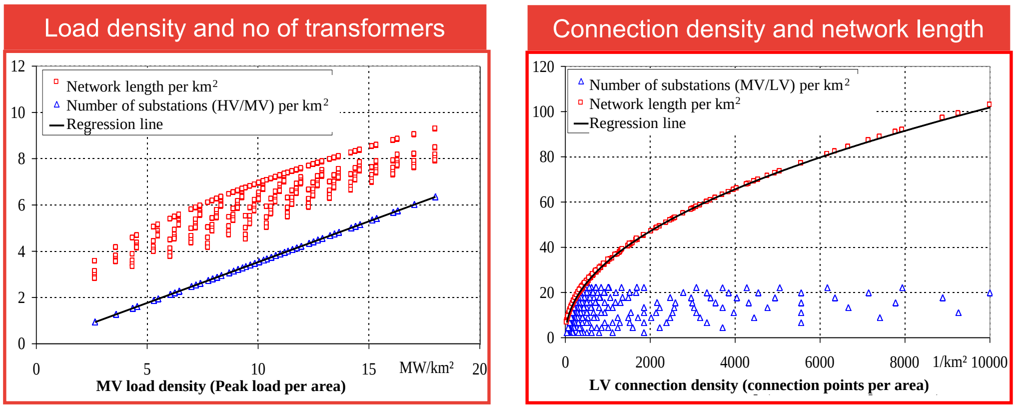
- load density (Peak load per area); and
- connection density (Number of connections per area).

The scale of the network assets is covered by the outputs:

- network length per area; and
- number of transformers per area.

The hypothetical networks were constructed for the HV, MV and LV and transformation network levels.

Figure 6. Results from model network analysis



Source: Frontier Economics/Consentec

The main results for the relationship between the inputs and the outputs are described in **Figure 6**:

- **Impact of load density on the number of transformers** – the left hand figure shows a linear relationship between the load density in an area and the number of transformers for the HV/MV network level. Hence, an increase in the MV load density leads to an increase in the necessary number of transformers by a fixed factor.

- **Impact of connection density on network length** – the right hand figure shows a relationship between the connection density LV and the LV network length. An increase in the connection density also increases the network length. However, the functional relationship is not linear, but can be proxied by a square root relationship.

The Model network analysis identified load and connection density per grid level as cost drivers. In both cases density is relative to a reference area, but these ratios must be converted into absolute metrics in order to use them as output variables. Where a linear relationship exists this is performed by multiplication by the area, thus obtaining an absolute magnitude – network peak load – from the relative metric.

Hence, E-Control used peak load for the whole service area as the proxy for the dimensioning of transformation (HV/MV, MV/LV) level. To get standardised data from the companies E-Control asked companies for a common definition for MV and LV peak load, collected the figures according to this definition and did a final plausibility check.

Because of the non-linearity of connection density, however, the reference area is not stripped out of the equation by multiplication. To get the network length (l_i)

for one area (A_i) one has to calculate the square root of the product of network connection points (NA_i) and the size of the area (A_i). To get the network length for the whole service area (l) one has to calculate the length for each subarea and then sum it up (**Figure 7**).

Figure 7. Connection density - from relative to absolute values

$$\frac{l_i}{A_i} = \sqrt{\frac{NA_i}{A_i}} \quad l_i = \sqrt{NA_i \cdot A_i} \quad l = \sum_{i=1}^{n} l_i = \sum_{i=1}^{n} \sqrt{NA_i \cdot A_i}$$

Source: E-Control

Hence, the information requirements increased for calculating the model network length as an absolute for HV, MV and LV. E-Control had to decide and collect data for:

- Standardised definition of connection points;
- Number of connection points (HV, MV, LV) per area;
- Definition of the geographical fragmentation of the service area.

E-Control decided to collect the number of connection points (HV, MV, LV) for each company per municipality. E-Control decided to use Zählsprengel (subunit of municipality) as the smallest unit for geographical fragmentation of the service area. E-Control estimated the number of LV connection points for each Zählsprengel using the number of buildings in each Zählsprengel (sourced from Statistik Austria). E-Control used different geographical fragmentation of the service area depending on the network level:

- *HV-level*: whole service area
- *MV-level*: service area per municipality
- *LV-level*: service area per Zählsprengel (where the size of the area depends on sparsity of buildings).

Based on these data E-Control calculated for every company model network length for HV, MV and LV level and used them as an output in the benchmarking analysis. E-Control called the network length *Transformed Weighted Connection Density* indicating the information which is included in the number.

Second step – model specification

In the second step E-Control used the results from the model network analysis to specify a base model for further analysis. The base model included:

- Total Costs;

- MV and LV peak load;
- HV, MV and LV Transformed Weighted Connection Density.

E-Control defined further potential cost-drivers partially based on companies' proposals e.g.

- Cabling LV / MV;
- Number of metering points; and
- MV-MV-Transformers.

In the following E-Control tested the statistical significance of the base model and further outputs and environmental factors. Non-significant outputs were excluded from the model.

Model specification and calculation of efficiency scores

E-Control defined two models and calculated preliminary efficiency scores for the network companies. E-Control sent the first results to the companies for consultation. The first sample consisted of 21 network companies (two companies were excluded as outliers from the initial sample of 23). The relevant efficiency scores were derived from the average of the DEA and MOLS results.

Table 4. First model specification

	DEA (1 tfWCD)	MOLS (1 tfWCD)
Input	Total costs	Total costs
Output	Peak load MV	Peak load MV (square)
	Peak load LV	Peak load LV
	Weighted sum of HV, MV and LV Transformed Weighted Connection Density	Weighted sum of HV, MV and LV Transformed Weighted Connection Density

Source: E-Control

In the consultation process an external consultant replicated the first results from E-Control for the network companies and proposed two changes in the model specification:

- *Exclusion of one outlier* – it turned out that one company dominated as the peer company for many others. By excluding this company the average efficiency values increased very strongly.
- *Separate Transformed Weighted Connection Density for each network level for DEA* – The companies argued that by using a weighted sum over all network

areas the structural characteristics of the companies are not sufficiently reflected. Hence, using three separate Transformed Weighted Connection Density for HV, MV and LV in the DEA increases the quality of the analysis.

E-Control decided to take both issues into account. E-Control excluded the identified outlier from the sample.

In the following E-Control analysed the DEA efficiency scores using three separate Transformed Weighted Connection Density for HV, MV and LV. E-Control come to the conclusion that

- the efficiency results especially for one company increases very strongly from 77% to 100% when using DEA (3 tWCD) instead of DEA (1 tWCD). this was due to unique characteristics with regard to one output/input relation for this company;
- comparing the other output/input relations with three other companies revealed consistently higher scores for the three other companies;
- using only DEA (3 tWCD) instead of DEA (1 tWCD) would overestimate the efficiency score of the company with the unique characteristics for one output/input relation compared to the other companies.

Hence, E-Control decided not to substitute but to complement the DEA (1 tWCD) with the DEA (3 tWCD). However, E-Control put a lower weighting on the results from DEA (3 tWCD) when calculating the final efficiency scores:

Efficiency scores = 20%·DEA (3 tWCD) + 40%·DEA (1 tWCD) + 40%·MOLS (1 tWCD)

The final model specification is summarised below.

Table 5. Final model specification for benchmarking analysis

	DEA (3 tfWCD)	DEA (1 tfWCD)	MOLS (1 tfWCD)
Weight	20%	40%	40%
Input	Total costs	Total costs	Total costs
Output	Peak load MV	Peak load MV	Peak load MV (square)
	Peak load LV	Peak load LV	Peak load LV
	HV Transformed Weighted Connection Density	Weighted sum of HV, MV and LV Transformed Weighted Connection Density	Weighted sum of HV, MV and LV Transformed Weighted Connection Density
	MV Transformed Weighted Connection Density		
	LV Transformed Weighted Connection Density		
Results	Average efficiency: 90,87% 7 companies 100% efficient Lowest efficiency score: 70,44	Average efficiency: 87,08% 5 companies 100% efficient Lowest efficiency score: 66,40%	Average efficiency: 89,15% 5 companies 100% efficient Lowest efficiency score: 71,37%
Sample	20 companies	20 companies	20 companies

Source: E-Control

5.4 Approach to the treatment of exogenous industry-wide cost increases

There are different indices available to take into account exogenous cost increases on controllable costs, e.g. Consumer Price Index, Retail Price Index, Producer Price Index. Regulators often use the Consumer Price Index.

E-Control decided to use a combination of different indices instead of one index to better reflect the cost structure of a network company. E-Control calls the combination *Distribution company price index*, which consists of:

- *Wage Index (TLI):* Proxy for development of staff costs (Weight: 40%)
- *Building Price Index (BPI):* Proxy for development of capital costs and cost of materials (Weight: 30%)
- *Consumer Price Index (VPI):* Proxy for development of other costs (Weight: 30%)

The weights should reflect the average cost structure of the network companies in Austria.

5.5 Approach to the treatment of capital expenditure during regulatory period

E-Control introduced the so called investment factor in the 2nd regulatory period starting 2010. The main objective of the investment factor is to cover additional investments during regulatory period due to replacement and extension investments, which exceed the capital costs of the base year for the 2nd regulatory period 2008. The investment factor has two main objectives:

- *Instrument to ease the t-2 problem* – In case of a step increase in investments, the t-2 problem still remains, because the investment factor is calculated using t-2 values. However, the included mark-up may ease the t-2 problem;
- *Investment incentive* – E-Control states that the investment factor should give companies an incentive to invest, also in innovation. The incentives stems from the included mark-up.

The investment factor constitutes a cost-plus element in the incentive based regulatory system in Austria, as it effectively allows a delayed partial cost-pass through of investments. One important feature of the investment factor is the assumption of E-Control that all investments from 2006 are efficient and no productivity factors applies to them when calculating the investment factor. The investment factor is determined by

$$\textbf{Investment factor}_t = \textbf{capex}_{t-2} - \textbf{adj capex}_{2008} + \textbf{Mark-up}$$

So for the year 2012 the relevant figures for calculating the investment factor are:

- **capex_{t-2}** – for year 2012 the relevant capital costs 2010 are
  - $\text{Depreciation}_{2010}$
  - $\text{WACC}\cdot\text{RAB}_{2010}$
- **adjcapex_{2008}** – the capex 2008 of the base year for the 2nd regulatory period are grouped into

- $capex_{2008\_until\ 2005}$ – depreciation and WACC·RAB for investments until 2005, where only the efficiency depending productivity factor applies;
- $capex_{2008\_past\ 2005}$ – depreciation and WACC·RAB for investments past 2005, where no productivity factor applies;
- $adjcapex_{2008} = capex_{2008\_until\ 2005} + capex_{2008\_past\ 2005}$

- **Mark-up – 1.05%·cum gross investments$_{until2009}$,** which means that the Mark-up 2012 = 1.05%·(gross inv$_{2009}$ + gross inv$_{2010}$)

It is too early for a final evaluation of the investment factor and how it really affected the companies' behaviour. However, some generic statements are possible:

- E-Control assumes all investments past 2005 as efficient. Hence, it is unclear how E-Control will treat investments past 2005 in the 3rd regulatory period (e.g. exclude them from benchmarking);
- E-Control always was of the opinion that the WACC gives the „right" incentive for investment. The mark up approach is in principle inconsistent with this view. It is therefore unclear how E-Control will treat the mark-up in the 3rd regulatory period.

5.6 Approach to the treatment of operating expenditure during regulatory period

Additionally to the investment factor E-Control also introduced an opex factor in the 2nd regulatory period. The main objective of the opex factor is to cover additional operating costs during regulatory period due to change in the scale of activities. The change in scale is measured by the development of

- Metering points HV/MV/LV
- Network length HV/MV/LV

The opex factor may also take negative values, however, for the HV and MV level the opex factor is capped at zero. Hence, a negative value only applies for the LV level.

In order to determine the opex factor the number of metering points and network length are annually compared with the base year 2008 figures. For the comparison t-2 values are used, e.g. for opex factor 2012 values of 2010 are compared with Base year 2008. The additional operating expenditures are calculated by multiplying unit costs with the difference between comparison year and base year. The unit costs are defined by

- Metering points – 50,0 EUR

- Network length LV – 1.900,0 EUR / km
- Network length MV – 3.154,0 EUR / km
- Network length HV – 11.077,0 EUR / km

Thus, an increase in the numbers of metering points by e.g. 1.000 increases the costs by 50.000 EUR.

5.7 3rd regulatory period (2014-2018) – Outlook

E-Control and the network companies are currently discussing the design of the regulatory system for the 3rd regulatory period. There are some open questions, which have to be resolved until the middle of 2013:

- **Quality regulation** – Currently, there is no quality regulation in place. This was mainly due to the lack of a legal basis. In 2010 the energy law was amended, including provision for quality regulation. E-Control stated that it wants to introduce quality regulation in the 3rd regulatory period. While, no official publication is currently available on quality regulation, we would expect a similar system to that in Germany.

- **Benchmarking analysis** – E-Control plans to update the benchmarking analysis for the 3rd regulatory period. However, it is still unclear how E-Control will treat investments past 2005, which are assumed as being efficient when calculating the investment factor.

- **Dealing with new challenges** – there are some discussions if the current regulatory system and the tariff structure can deal with new challenges related with energy efficiency and decarbonisation.

5.8 Key lessons

The framework of incentive regulation in Austria is designed to facilitate efficiency savings and necessary investments for a large number of companies. Especially in the 2nd regulatory period the focus was more on incentives for investments which was reflected by the introduction of the investment factor, which results in a partial cost-pass through of investments. The key lessons that can be learnt from electricity distribution network regulation in Austria are described below.

- **Use of multiple benchmarking techniques,** to lower risk of setting unachievable targets.

- **Use of weighted sum of efficiency scores** from three different model specifications to deal with advantages and disadvantages of different benchmarking techniques.
- **Use of model network analysis for output selection,** to cover structural differences between network companies. Model network analysis helps to identify relevant cost drivers and identify functional relationships between inputs and output.
- **Use of „Distribution cost price index"** instead of CPI, to better reflect relevant costs of an electricity network company for indexing costs.
- **Use of investment factor in 2nd regulatory period,** which allows a partial cost-pass through of capital costs as incentive for investments. Investment factor also includes a financial mark-up for gross investments during 2nd regulatory period.

6 Regulation in Germany

6.1 Overall approach

The German electricity market was fully liberalised in 2001. There are four major vertically integrated groups (E.ON Energie AG, RWE AG, EnBW AG, and Vattenfall Europe AG) and more than 800 other electricity companies in Germany.

The regulatory authority is the Federal Network Agency, Bundesnetzagentur (BNetzA), which is responsible for setting the network tariffs.

There were two phases in the regulation of electricity networks:

- *Cost-plus regulation from 2001-2008*;
- *Incentive-based regulation since 2009*.

The German regulatory system since 2009 is based on a revenue cap with a regulatory period of 5 years. The 1st period lasts from 2009-2013, and the 2nd period will start from 2014-2018. Currently, Bundesnetzagentur is working on the design of the 2nd regulatory period starting in 2014. However, the decree of freedom of the Bundesnetzagentur is much restricted by the detailed regulations in the Incentive Regulation Decree (ARegV). For example, the decree states that Bundesnetzagentur has to use certain outputs and techniques in the benchmarking analysis.

6.2 Overall ethos of the regime

The details of the revenue cap regulation in Germany are fixed in the ARegV. The ARegV determines how to

- calculate the base year costs for the regulatory period; and
- adjust the base year costs during the regulatory period.

One key feature when calculating the base year costs is that ARegV states that no cost forecasts must be used. According to § 6 ARegV the base year costs for the regulatory period are determined by using t-3 figures, i.e. year 2006 for the 1st regulatory period starting in 2009, and year 2011 for the 2ndregulatory period starting in 2014.

Hence, there is a t-3 time lag for costs included in the revenue path. However, the regulatory formula includes further instruments to cover increasing costs due to a change in the supply task of a network company, the so called *expansion factor*. Other adjustment factors for the base year costs are the productivity factor and the consumer price index.

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Attachment EGD/Union.2d.6
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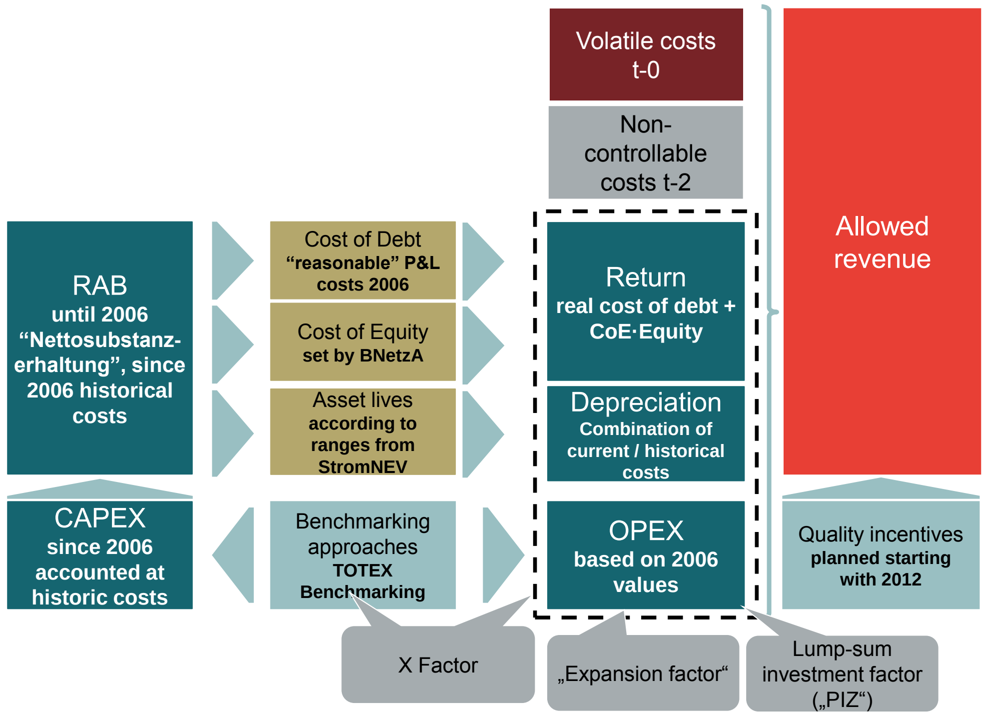
Non-controllable costs, e.g. costs for transmission charges, are updated annually with a t-2 lag during the regulatory period. According to § 11 (5) there is a further cost category – volatile costs – which are updated with no time lag. Volatile costs are the costs for network loses.

Figure 8. Building blocks for 1st regulatory period (2009-2013)



Source: Frontier Economics

In the following we will describe how the allowed costs and revenues are derived for

- base year costs 2006
- during regulatory period 2009-2013

in the 1st regulatory period according to ARegV.

6.2.1 Determining base year costs for 1st regulatory period

The relevant **base costs for 2006** consist of:

- **Controllable opex 2006** – which were audited by the BNetzA and based on P&L figures for the year 2006. Opex by default are treated as controllable.

- **Depreciation 2006** – the companies have to use regulatory depreciation periods which may differ from accounting values. The StromNEV determines ranges for depreciation periods for different asset classes.
  - Depreciation for „old" assets before 2005 – for old assets the depreciation is based on a combination of current and historical asset values. The current asset values are used for the part of the assets financed by equity, where the equity ratio is capped at 40%. Historical asset values are used for the debt financed part.
  - Depreciation for "new" assets past 2005 – for "new" assets depreciation is calculated using historical asset values irrespective of whether they were financed by equity or debt.
- **Cost of debt 2006** – are based on P&L figures. Hence, the allowance of cost of debt is a pass through item up to a "usual market level".
- **Return on Equity** – is based on a risk free rate plus an adequate risk premium. The risk premium is calculated by CAPM
  - *"old assets"* – a real Return on Equity is used.
  - *"new assets"* – a nominal Return on Equity is used.
- **Determining Equity –** the equity ratio for total assets is capped at 40%. Equity in excess of the 40% is treated as debt. In order to calculate the equity one has to distinguish between
  - *"old assets"* – current asset values are used.
  - *"new assets"* – historical asset values are used.

6.2.2 Revenue cap formula during regulatory period 2009-2013

The revenue cap formula according to ARegV for the 1st regulatory period is shown below:

$$\mathbf{Revenues_t = Costs_{non\text{-}contr,\ t} + (Costs_{temp\ non\text{-}contr,\ 2006} + Costs_{contr,\ 2006} \cdot (1 - V)) \cdot (CPI - PF) \cdot ExpF_t + Q_t + (VC_t - VC_{2006})}$$

According to ARegV the same formula will apply for the 2nd regulatory period form 2014-2018 where the base year costs will be determined by 2011 values.

In the following we will describe the individual components. For the expansion factor (ExpF) see Section 6.4 and for quality regulation (Q) see Section 6.5.

Non-controllable costs ($Costs_{non\text{-}contr,\ t}$)

The non-controllable costs are defined in § 11 (2) ARegV. The main important costs items are the costs for transmission charges and concession taxes. Non-controllable costs are treated as a cost-pass through item with a t-2 time lag. This means that for the allowed revenues in year 2012 the costs figures of 2010 are used.

Volatile costs (VC_t)

The volatile costs are defined in § 11 (5) ARegV. For electricity distribution networks the volatile costs only consists of the costs for network losses. Volatile costs are annually adjusted with reference to the value in the base year. In contrast to non-controllable costs there is no time lag involved, e.g. for revenues 2012 forcasted 2012 values are used.

General productivity factor (PF)

According to §9 ARegV the general productivity factor basically covers the average productivity improvement of the whole industry and Hence, it applies to all companies. The final values for PF in the § 9 (2) ARegV – 1.25% for the 1st and 1.5% for the 2nd regulatory period – were the result of political negotiation in Parliament.

PF has been annulled in a recent decision by the German Supreme Court, Bundesgerichtshof (BGH)[9]. However, an amendment of the German energy law has passed the German Bundestag on December 2nd, 2011 including an article on the generic productivity factor (PF) of § 9 ARegV.

Individual efficiency factor (V_t)

According to §16 (1) ARegV one has to distinguish between the 1st and the following regulatory periods when calculating V_t:

- **1st regulatory period** – the elimination of the inefficient costs – which are equal to the controllable costs (**$\mathbf{Costs}_{contr,\ 2006}$**) –is distributed over two regulatory periods, 10 years. Hence, the annual value of V is 0.1 in year 1, 0.2 in year 2, etc.

- **Following regulatory periods** – the elimination of the inefficient costs – which are equal to the controllable costs (**$\mathbf{Costs}_{contr,\ 2010}$**) – is distributed only over one regulatory period, 5 years. Hence, the annual value of V will be doubled to 0.2 in year 1, 0.4 in year 2, etc., increasing the cost pressure on the companies.

9 Bundesgerichtshof, Beschluss EnVR 34/10, June 28th, 2011.

To illustrate the calculation of V_t in a simple example for the 1st regulatory period. Let us assume that:

- total costs = 1.000
- efficiency score = 90%.

Then we get:

- $\textbf{Costs}_{\text{temp non-contr, 2006}}$ = 900 (= (1.100 – 100) · 90%)
- $\textbf{Costs}_{\text{contr, 2006}}$ = 100 (= (1.100 – 100) · 900)

In the 1st regulatory period, where the company has to eliminate controllable costs over 10 years, the company has to reduce its controllable costs every year by 10. The efficiency score is calculated by a benchmarking analysis (see Section 6.3).

6.3 Extent and type of benchmarking

In the following we will describe the benchmarking analysis which was used by Bundesnetzagentur to determine the efficiency scores which were used to calculate the controllable costs ($\textbf{Costs}_{\text{contr, 2010}}$). BNetzA undertook the analysis for 1st regulatory period (2009-13) in 2008 and will undertake an analysis for the 2nd regulatory period results (2014-18).

ARegV restricts the degree of freedom of BNetzA for the benchmarking analysis as it prescribes to use certain benchmarking techniques and outputs.

There are different steps involved when undertaking a benchmarking analysis:

- defining the benchmarking technique;
- defining the costs;
- defining the outputs which describe the supply task of the network companies; and
- calculating the efficiency values for cost targets.

Benchmarking technique – two approaches used

The term "benchmarking technique" refers to mathematical models that relate individual companies' inputs and outputs, and use the resultant productivity indicators to compare their efficiency with that of other firms. A variety of algorithms can be used to estimate relative efficiency. All these models compare the efficiency of the companies studied with that of best practice firms which is usually taken as 100%. Less efficient companies rate less than 100%.

According to § 12 ARegV BNetzA has to use two different benchmarking techniques:

- *Data Envelopment Analysis (DEA)* – which is a non-parametric/deterministic method; and
- *Stochastic Frontier Analysis (SFA)* – which is a parametric/stochastic method.

The main merits of SFA compared to DEA are that it

- Supports significance testing and other testing for functional form;
- Separates noise and efficiency, where DEA assumes that any difference between a company's observed costs and those of an efficient operator represents inefficiency.

BNEtzA has to use DEA with non-decreasing-returns-to-scale[10], hence, restricting the responsibility of the network companies for a non-optimal company size. Non-decreasing returns-to-scale means that companies are penalised for being "too big" but not for being "too small", which effectively favours smaller companies in the analysis. This was criticised during the consultation for the 1st regulatory period especially by bigger companies.

Due to the functional form of the cost function BNetzA explicitly uses constant-returns-to-scale for SFA.

Benchmarked costs – total cost and standardisation of capital costs

ARegV states that the benchmarking analyses should cover total costs. The use of total costs has the advantage that it does not create perverse incentives for suboptimal capital intensity as the substitution of operating by capital expenditures does not result in any change in the efficiency scores – unless it actually leads to a total cost savings. Non-controllable costs are eliminated from benchmarked costs.

According to § 12 (4a) ARegV two different costs are used for the benchmarking analysis:

- total costs without standardised capital costs;
- total costs with standardised capital costs.

By standardising costs various problems can be tackled:

- Differences in depreciation policies – some companies may have used in the past shorten depreciations periods than other, hence, distorting the capital costs and as a result the efficiency scores.

10 The term "returns to scale" refers to economies of scale achieved by varying company size. While a doubling of input factors (variable costs) results in a doubling of outputs under conditions of constant returns to scale (CRS), changes in inputs and outputs are not proportionate where variable returns to scale (VRS) apply.

- Differences in asset prices – historical assets are cheaper in nominal terms than new assets, which may distort efficiency scores.
- Differences in investment cycles – different investment cycles between the companies may distort the efficiency scores.

According to § 12 (4a) ARegV the standardisation of capital costs is done by using annuities based on indexed historical costs. The main difference between capital costs based on annuities in contrast to using straight line depreciations and WACC on the asset value is that

- Annuities result in stable capital costs over the lifetime of an asset;
- Depreciation and WACC on asset value result in decreasing capital costs over the lifetime of an asset.

Hence, the annuity approach cancels out the effect of different investment cycles. One potential disadvantage of the annuity approach is that it may favour companies with new assets, as the potential trade-off between higher capital costs and lower operating costs at the beginning and lower capital costs and higher operating costs at the end of the asset lifetime is neglected.

Defining the outputs using model statistical approaches

The main objective of the outputs is that they reflect the supply task of a network company. According to § 13 (4) ARegV the benchmarking analysis has to include as an output:

- number of connection points;
- service area;
- peak load; and
- network length.

In addition further outputs can be included if they increase they cover further cost-drivers not reflected in the above mentioned outputs.

BNetzA used a sequential approach for the final output selection which relied very much on statistical testing.

Step 1 – testing long list of output candidates

In a first step BNetzA defined the typical task of a distribution company as

- transportation work;
- capacity provision; and
- customer service.

and defined a long list of outputs and categorised them according to the distribution tasks. BNetzA then tested the statistical significance of the long list and eliminated non-significant outputs.

Step 2 – Testing optimal number of parameters for model

In the second step BNetzA tested the optimal number of outputs ("parameters") for the model specification by using statistical information criteria. Based on these calculations the optimal number was defined with 8 to 10 parameters.

Step 3 – Testing down final model

In the third step BNetzA tested the final model. Further, some outliers were excluded from the total sample based on statistical measures. In addition parameters were excluded based on non-significance and multi colinearity. The best model based on statistical testing consisted of 8 parameters (**Figure 9**).

Figure 9. Best model based on statistical testing

Variable	Estimate	Standard Error	t-value	Pr(>|t|)
Konstante	4774155.15	1028053.19	4.64	0.00
yCables.circuit.ms	5734.73	1712.82	3.35	0.00
yLines.circuit.ms	8302.97	1262.28	6.58	0.00
yConnections.hs.ms.ns	291.83	36.65	7.96	0.00
yPeakload.HS_MS.unoccupied.cor	38.61	9.29	4.15	0.00
yPeakload.MS_NS.unoccupied.cor	46.46	11.20	4.15	0.00
ySubstations.tot	-10234.73	1410.22	-7.26	0.00
yDR.tot	22.55	4.28	5.27	0.00
ynet.length.ns	-1931.85	751.63	-2.57	0.01

Source: Sumicsid/EE2

Step 4 – final outputs

In a final step BNetzA added further outputs to the model due to

- *ARegV* – which states that the service area has to be included as output;
- *Logical reasoning* – the best statistical model includes cables/lines for MV and LV, hence, BNEtzA decided to include also cables/lines for HV.

Final model specification and calculations

BNetzA defined four benchmarking models based on the

- two benchmarking techniques – DEA and SFA;
- two types of total costs – without/with standardised capital costs.

Table 6. Final model specification and results

	I. DEA ndrs	II. SFA	III. DEA ndrs	IV. SFA
Sample	195 (4 outliers removed from total sample of 199 companies)		193 (6 outliers removed from total sample of 199 companies)	
Inputs	Total costs without standardised capital costs		Total costs with standardised capital costs	
Outputs	Number of connection points for HV, MV and LV Lines HV Cables HV Lines MV Cables MV Network length LV Peak load HV/MV Peak load MV/LV Number of substations Service area Feed-in power of decentral generation			
Mean efficiency score	79%	87%	84%	89%
Min efficiency score	45%	70%	52%	77%
No companies on frontier	40	0	43	0
No companies < 60%	28	0	9	0

Source: Sumicsid/EE2

BNetzA analysed the results from the DEA and SFA by different approaches:

- *Outlier detection for DEA* – based on superefficiency, where companies with superefficiency scores above certain thresholds were excluded. In sum 6 companies were detected as outliers and excluded from the final sample.

- *Consistency test for SFA Results* – by testing if coefficients from SFA estimation behave consistent with OLS estimation. Nearly all coefficients have sensible signs and are significant.
- *Second stage testing* – BNetzA made two tests the Kruskal-Wallis-Test , which tests if efficiency scores differ for different groups of companies, and tobit regressions, which tests if efficiency scores are influenced by other parameters not included in the model specification. However, both tests were rejected.

Determining final efficiency scores

The final efficiency scores and resulting cost targets for companies are based on the "Best of Four" method. This means that should approaches generate different results the best of the four results are used. "Best of Four" is aimed to ensure that the cost target can be met and surpassed.

Additionally, a floor for the minimum efficiency score of 60% is applied. If a company is e.g. 55% efficient it will be treated "as-if" being 60%. Hence, the maximum value that inefficiency can take is 40% of controllable cost.

Benchmarking and small companies – option for simplified procedure

According to § 24 ARegV, network companies with less than 30.000 customers can opt for a simplified procedure. Companies applying for simplified procedure do not participate in the benchmarking analysis. However, the revenue cap still applies to them. The efficiency scores for these companies used for calculating the individual efficiency factor are determined for

- 1st regulatory period – efficiency score of 87.5% applied to all companies opting for simplified procedure.
- 2nd regulatory period – weighted average efficiency score from benchmarking analysis applied to all companies opting for simplified procedure.

Opting for the simplified procedure has additional consequences for the companies besides the benchmarking analysis:

- Assumption that 45% of total costs are non-controllable;
- Quality regulation does not apply for companies opting for simplified procedure;
- Lump-sum investment factor („PIZ") (see below) does not apply for companies opting for simplified procedure.

6.4 Approach to the treatment of capital expenditure during regulatory period

As described above the base year for the revenue cap has a t-3 time lag, which means that there is a delay of three to seven years between investments becoming integrated in the asset base. This delay raises issues related to how two types of investments are treated during the regulatory period:

- expansion of the network due to a change in the scale of the company; and
- replacement of old assets.

According to § 10 ARegV additional costs for investments – and operating costs – resulting from a change in scale are covered by the so called *expansion factor*.

In relation to replacement investment, BNetzA was of the opinion that the allowed capital costs from the base year should be sufficient to cover these costs. However, as a result of the political process, especially by lobbying of energy companies and interest groups, a lump-sum investment factor (so called *Pauschaler Investitionszuschlag* (PIZ)) was introduced for the 1st regulatory period to provide companies with additional funds especially for replacement investments.

Expansion factor

The objective of the expansion factor is to cover additional total costs during the regulatory period due to change in scale. The expansion factor was extended in 2011 to include impact from decentralised generation in 2011. Currently the change in scale is measured by the development of

- connection points HV/MV/LV;
- service area HV/MV/LV;
- injection points of decentralised generation; and
- load (incl. from decentralised generation).

The cost relationship between the change in the supply task and the total costs is based on a technical engineering approach („Model network analysis"). For the network level HV, MV and LV the relevant impact on costs results from an increase in the network length, whereas the transformation level HV/MV and MV/LV the relevant impact on costs results from the increase in the transformer capacities. The factor distinguishes the cost impact for different network level. The final expansion factor is calculated as a weighted sum of the network level expansion factors.

The calculation of the expansion factor is quite complex, which can be indicated by showing the underlying formula (**Figure 10**, **Figure 11**, **Figure 12**).

Figure 10. Expansion factor for the network level HV, MV and LV

$$EF_{t,\mathrm{Ebene\,i}} = 1 + \frac{1}{2} * \max\left[\frac{F_{t,i} - F_{o,i}}{F_{o,i}};0\right] + \frac{1}{2} * \max\left[\frac{\left(AP_{t,i} + z_i * EP_{t,i}\right) - \left(AP_{0,i} + z_i * EP_{0,i}\right)}{\left(AP_{0,i} + z_i * EP_{0,i}\right)};0\right]$$

where

$F_{t,i}$ = size of service area in year t for network level i;

$F_{0,i}$ = size of service area in base year for network level i

$AP_{t,i}$ = number of connection points t for network level i

$AP_{0,i}$ = size of service area in base year for network level i

$EP_{t,i}$ = DecGen injection points in year t for network level i

$EP_{0,i}$ = DecGen injection points in base year for network level i

z_i = scaling factor for DecGen injection points

Figure 11. Expansion factor for transformation level HV/MV and MV/LV

$$EF_{t,\mathrm{Ebene\,i}} = 1 + \max\left[\frac{L_{t,i} - L_{o,i}}{L_{o,i}};0\right]$$

where

$L_{t,i}$ = Peak load in year t in network level i

$L_{0,i}$ = Peak load in year t in network level i

Figure 12. Expansion factor over all network levels

$$EF_t = \sum_i \left(EF_{t,Ebene_1} \cdot \frac{GK_{0,Ebene_1}}{GK_0} \right)$$

where

$GK_{0,\mathrm{Ebene\,i}}$ = total costs in base year for network level i

The calculation of the scaling factor z for decentralised generation adds further complexity into the calculation (**Figure 13**).

Figure 13. Calculation of the scaling factor

$$
z_i = \begin{cases}
1, wenn \;\; i = HS \\
1, wenn \;\; \dfrac{I_{t,i+v}}{L_{t,i}^{Entnahme}} \leq 0{,}3 \\
\max\left[\dfrac{\sqrt{EP_{t,i}} - \sqrt{EP_{0,i}}}{\sqrt{AP_{t,i} + EP_{t,i}} - \sqrt{AP_{0,i} + EP_{0,i}}};1\right], wenn \;\; \dfrac{I_{t,i+v}}{L_{t,i}^{Entnahme}} > 0{,}3 \;\; und \;\; i \neq HS \\
mit \;\; AP_{t,i} = AP_{0,i}, wenn \;\; AP_{t,i} < AP_{0,i} \\
mit \;\; EP_{t,i} = EP_{0,i}, wenn \;\; EP_{t,i} < EP_{0,i}
\end{cases}
$$

where

I = installed decentralised capacity

Entnahme = withdrawal

The inclusion of decentralised generation into the expansion factor had a big impact on the allowed additional costs for network companies especially located in the south of Germany due to the large amount of PV installations.

Lump-sum investment factor (PIZ)

The main objective of the PIZ is to give companies a further investment incentive, especially for replacement investments (which are not covered by expansion factor). As mentioned above this instrument was introduced by the political process due to lobbying of the companies. They argued that the capital costs included in the base year for the 1st regulatory period were not sufficient to finance future increasing replacement investments. The PIZ only applies for the 1st regulatory period and should be replaced by quality regulation.

The PIZ is designed as a one-off mark-up on annual revenues during the regulatory period by 1% of standardised capital costs. The companies have to apply for PIZ and there is an ex post monitoring by BNetzA to check that companies' investments are at least equal to the PIZ.

In connection with the expansion factor, the PIZ could lead to a double counting of investments. However, the BNetzA accepts this double counting because

- delineation of expansion and replacement investments might be too complex; and
- the PIZ only has a minor impact on total revenues.

6.5 Extent of "quality regulation"

The ARegV sets the framework for quality regulation in Germany. It states that quality regulation shall secure the reliable operation of power grids in the long term while taking into account different quality levels and structural differences between network companies. According to § 19 Abs. 1 ARegV there shall be a symmetric bonus/malus for over- and underperformance. The quality regulation shall be designed in a revenue neutral way over the whole industry. This means that on average all companies' rewards and penalties from quality regulation should be equal. Although, there is no impact from quality regulation on total revenues over the whole industry, individual network companies and user will be affected by higher/lower tariffs.

Quality regulation was first implemented in 2012. The quality regulation is included as a Q-factor in the regulatory formula. In the following we will describe the main items of quality regulation in Germany:

- *Quality indicator* – BNetzA uses the SAIDI (System Average Interruption Duration Index) as the first main indicator. There may be a further differentiation of the indicators with SAIFI and CAIDI. BNEtzA deliberately does not use energy not supplied.
- *Reference value* – the reference values is a 3-year average rather than a one year figure. Using a rolling average should compensate for short-term (stochastic) fluctuations. The reference value further considers structural differences between the companies.
- *Incentive rate* – the incentive rate is based on an empirical analysis using international studies on values of lost load. BNetzA did not undertake a customer survey.
- *Caps/Floors* – are used for risk mitigation and set at +/- 5% of controllable costs.

6.6 Key lessons

The framework of incentive regulation in Germany is designed to facilitate efficiency savings and necessary investments for a large number of companies. The key lessons that can be learnt from electricity distribution network regulation in the Germany are described below.

- **Use of multiple benchmarking techniques**, to lower the risk of setting unachievable costs targets.

- **Use of standardised cost bases for benchmarking,** to cover asset valuation and investment cycle problems. This helps to avoid over-/underestimated efficiency values for network with a different age structure.

- **Use of regression-based benchmarking**, to allow for statistical testing and to distinguish between "noise" and inefficiency.

- **Use of simplified procedures for small companies,** to reduce the complexity for small companies and the impact of lumpy investments on efficiency scores for small companies.

- **Quality regulation,** takes into account the structural differences between the network companies when setting quality targets. The impact of short term fluctuation is smoothed by using rolling 3-years average. SAIDI, not energy not supplied, as the relevant quality indicator.

7 Regulation in the Netherlands

In this chapter, we describe how electricity distribution networks are regulated in the Netherlands. We also discuss the key lessons that can be drawn out from this regulatory regime.

7.1 Overall approach

The Electricity and Gas Acts in the Netherlands specify that the regional gas and electricity networks in the Netherlands be regulated under a yardstick competition regime. The general principle of a yardstick regime is that a single price control is set for the industry. In other words, each of the 10 regional DSOs face the same X-factor, and the X-factor is the same in each year of the price control period. However, the framework of regulation in the Netherlands has evolved over time.

First price control (2001 – 2003)

When the first price controls were proposed for regional electricity companies, DTe calculated a different X-factor for each company. This was based on an interpretation of the law that assumed that a transitional period existed to allow for companies to converge to a common efficiency level. Consequently, DTe undertook a benchmarking exercise to calculate the extent to which each operator was inefficient relative to the industry efficiency benchmark. DTe's objective at that time was to base the allowable revenue in 2003 on these efficient costs (i.e. to allow catch-up to the frontier between 2000 and 2003, and to have a uniform control applied from that point forward).

However, DTe's decision was appealed by nearly all companies – first to DTe, who submitted a review decision a year later; and then to the Court (CBB). Companies appealed the decision on the grounds that the relative efficiency scores derived through the benchmarking analysis did not meet their expectations of how companies compared to each other. However, in the course of the legal appeal, and a parallel appeal on supply tariffs, the court focused on the question of whether DTe could set company-specific X-factors in any case. The court found, based on its interpretation of the law, that a uniform X-factor was required, essentially eliminating the need to review the benchmarking methodology itself. As a result, a uniform productivity-factor of 3.2% was applied to the industry.

Second price control (2004 – 2006)

The Minister of Economic Affairs proposed a change in the law to clarify that DTe was allowed to set company specific productivity factors for an interim period. This provided a legal basis for DTe's methodology and allowed for company-specific productivity-factors to be introduced for the period 2003-2006 (once the law was enacted). DTe's revised objective was to base the allowable revenue in 2006 on efficient costs (i.e. to allow catch-up to the efficiency frontier by 2006 and to have a uniform control from that point forward).

The target included two components, a company-specific complement, determined by comparative benchmarking, and an industry productivity component, determined by total factor productivity (TFP) analysis. Quality targets were introduced in 2005, but these were set to zero in the electricity sector in the second price control period.

The second regulatory review is thought to have effectively finalised the framework within which future reviews would be conducted. The details were not appealed by the industry

Current approach

A uniform productivity factor is currently set for all companies based on industry average performance. This is measured as the change in Total Factor Productivity (TFP) of the industry. The yardstick formula is defined as below.

$$TR_{t,i} = TR_{t-1,i} * \frac{1 + CPI - X + Q}{100}\%$$

For each operator, the current period's weighted basket of tariffs must equal the previous period's weighted basket of tariffs, *plus* the consumer price index, *less* the "X-factor", *plus* the "Q-factor". Companies able to beat this average would make (and retain) excess returns until the rest of the industry caught up.

We now turn to the derivation of these factors.

7.2 Extent and type of benchmarking

There are three main components to the price control approach adopted by DTe, the X-factor, the Q-factor, and an adjustment for estimation error. These are described in sections 7.2.1 to 7.2.3 below.

7.2.1 The X-factor

DTe sets a uniform X-factor for each of the 10 DSOs in the industry. This X-factor is calculated by using a TFP approach, which is essentially an average of the ratio of standardised inputs and outputs of each of the firms.

Standardised inputs

The standardised input used in the calculation of productivity growth, is standardised economic cost. This is consists of:

- a return on a standardised asset base (WACC times the standardised asset value); plus
- a depreciation allowance based on the standardised asset value; plus
- operating costs ((including costs for transmission charges).

Standardised outputs

The standardised output used in the calculation of productivity growth is a composite output variable. It is calculated as a sum of all the services in the tariff baskets (for example transported kWhs and reactive power) charged to consumers weighted by average sector prices in the base year.

The composite output is a weighted sum of:

- the amount of annual transport fees (i.e., number of customers);
- kW-max;
- kW-contracted;
- kWh (peak and base);
- kVArh; and
- annual connection fees.

Figure 14 below illustrates an example of how this composite output variable is calculated.

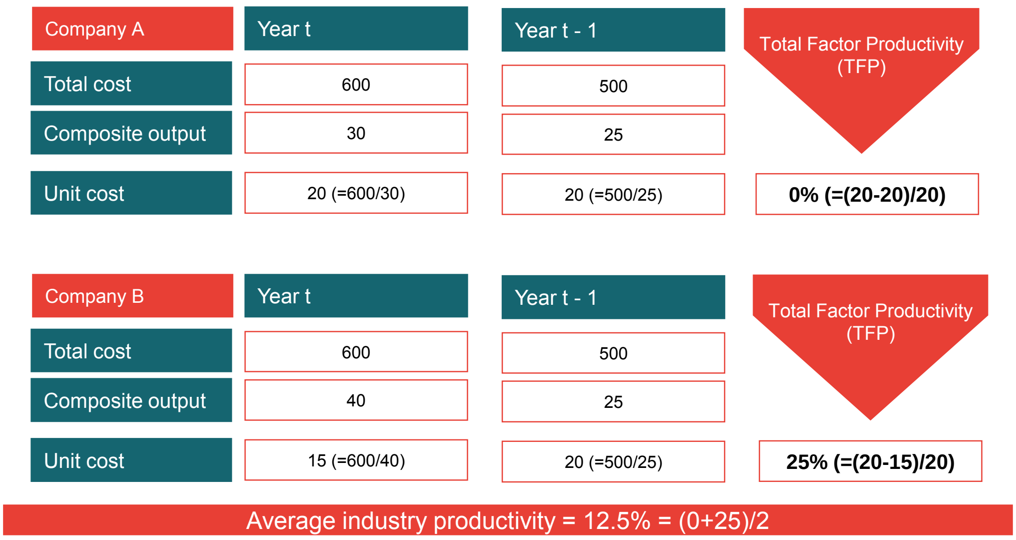
Figure 14. Example of composite output variable calculation

Example	Output – year t	Output – year t - 1	Base year tariffs
Product 1 (eg., kW-max)	100	120	1
Product 2 (eg., kW-contracted)	120	120	2
Composite output	**340 = (1*100) + (2*120)**	**360 = (1*120) + (2*120)**	

Source: Frontier Economics

Company productivity growth is then calculated as the proportionate change in unit costs, based on this composite output variable. Figure 15 below illustrates an example of how TFP for the industry is estimated once the standardised inputs and outputs have been determined.

Figure 15. Example of TFP calculation



Source: Frontier Economics

Figure 15 shows that if two companies have the same change in cost levels but different rates of growth in the composite output their calculated productivity growth rate will be different. In this example, as Company B's output level has grown faster than that of Company A for the sample change in cost levels, Company B's TFP is higher than that of Company A. In other words, Company B is able to deliver more units of output for a given cost level, and is therefore more efficient.

DTe sets a single industry X-factor for each of the companies. The average industry X-factor in the example in Figure 15 is 12.5%

7.2.2 The Q-factor

In 2005, DTe introduced a form of quality regulation into its determination of the price cap in the electricity sector. The so-called Q-factor is intended to reduce the incentive to companies to reduce costs at the expense of quality of service.

The quality factor allows for an adjustment to each company's tariff basket to reflect quality performance in the previous period. The adjustment is symmetric, in the sense that a company that outperforms will receive an increase in allowed revenues and a company that underperforms receives a decrease in allowed revenues. DTe imposed boundaries on the size of adjustment of +/- 5% of total revenue in a given year. Performance is measured in terms of the monetary value that customers place on interruptions (SAIDI), which is determined by dividing the total duration of the interruption in minutes by the total number of connected customers.

7.2.3 Adjustment for estimation error

DTe adjusts the opening value of allowed revenues at the start of each period for the difference between the assumed average change in productivity in the previous period and the actual average change in productivity (i.e. an adjustment will be made at the start of each regulatory period for estimation errors in the previous regulatory period). This essentially represents the outperformance of the industry over the previous three years, relative to the expectation that DTe had of its productivity. This is done to ensure that on average the industry does not earn a windfall gain, or face a windfall loss, because of forecasting error by the regulator.

There are two types of outperformance that are treated differently by DTe

Industry outperformance is clawed back

The actual average change in productivity for the period is calculated as the weighted average of the productivity improvement of these efficient companies. The difference between this actual average change in productivity, and the regulator's assumed average change in productivity, will have provided a windfall gain or loss to the industry. The industry retains this outperformance to the end of the regulatory period, but the value of this outperformance is clawed back to ensure that the average industry return is actually equal to the cost of capital.

Individual company outperformance is retained

DTe does not clawback the outperformance of individual companies. In other words, individual company productivity growth that is higher than the average change in industry productivity, is not expected to be clawed back by the regulator.

Figure 16. Example of estimation error

X-factor	Actual average productivity change	Company A's actual productivity change
3.2%	4.0%	5.0%

Source: Frontier Economics

Figure 16 above illustrates an example of how DTe would treat an estimation error. In this example, if the X-factor is 3.2% for the industry and the actual average change in productivity is 4% the X-factor is adjusted in the next period to take account of the value of the additional 0.8% productivity improvement by the industry on average. However, if a company has a productivity growth of 5% the additional 1% improvement, relative to the industry average, is retained by the company and is not shared with customers. This provides a strong incentive to companies to outperform the industry average and is the basis of yardstick competition.

7.3 Approach to treatment of capital expenditure

As described in section 7.2 above, revenue caps are set on the basis of a TFP analysis of total costs. Total costs in the cost base include an estimate of capital costs and depreciation. This section describes how DTe models these costs.

7.3.1 Treatment of capital expenditure

Capital costs represent an important part of total costs. However, DTe argues that simply collecting the reported capital costs from company accounts might bias any comparative analysis, as some differences in reported capital costs are likely to arise from the use of different accounting policies (e.g. assumed asset lifetimes, choice of depreciation methodology etc). DTe therefore requires a standardised annual capital cost constructed by applying the same accounting rules to the investments made by each company.

This involves:

- using the same depreciation life time for a given asset type;
- using straight-line depreciation methodology;
- allowing the same rate of return on the standardised asset value; and
- treating intangible assets in a consistent way.

7.3.2 Approach to the treatment of cost of capital

The return on capital is calculated by applying a weighted average cost of capital (WACC) to the standardised asset value. A real pre-tax WACC was calculated using the Capital Asset Pricing Model (CAPM). The CAPM assumes that investors have to be compensated for systematic risks (market risks), while non-systematic risks (company-specific risks) may be diversified and do not warrant an additional risk premium.

The WACC is calculated as the weighted sum of the cost of equity and the cost of debt. The weight on equity is equal to the level of gearing and the weight on debt is equal to one minus the gearing level.

7.3.3 Treatment of depreciation

A straight-line depreciation allowance is calculated for the standardised asset value using assumed useful lives for different asset classes. The useful lives vary from 5 years for IT equipment to 50 years for connections to the grid. The asset value itself assumes similar approaches to the valuation of assets and the standardisation of deprecation periods

7.4 Key lessons

There are a number of elements of the regulatory regime in the Netherlands that provide strong efficiency incentives. The key lessons that can be drawn from regulation in the Netherlands are described below.

- **Treatment of outperformance creates strong efficiency incentives**: Company outperformance relative to average industry performance is not clawed back by the regulator. This provides strong efficiency incentives.

- **Distortions are reduced by the use of standardised cost bases**: This helps smooth out differences in asset valuation policies, and create comparisons on a more like-for-like basis

- **Total cost approach accounts for trade-offs**: Trade-offs may arise between operating and capital expenditure levels, and any potential accounting concerns relating to the capitalisation of operating expenditure. A total cost accounts for these trade-offs.

- **Light touch approach**: Minimised bureaucratic involvement by the regulator in the managerial decisions of the businesses

- **Quality regulation:** Reduces the incentive to companies to reduce costs at the expense of quality of service.

The relatively small number of DNOs in the Netherlands facilitates the use of a light touch approach to regulation. Some of the elements of the regulatory regime in the Netherlands, therefore, may not be directly applicable to the Norwegian context. Nevertheless, other elements, such the standardisation of cost bases, are more relevant.

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Exhibit L1.EGD/Union.2
Attachment EGD/Union.2d.6
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Regulation in the Netherlands

8 Implications for Norway

In this Chapter, we consider the implications for regulation in Norway from the case studies we have described in the preceding chapters. In turn:

- we first describe our approach to considering "lessons learned" for Norway; and
- then discuss options for changes to the current regime in Norway and the possible tradeoffs associated with each.

8.1 Approach to considering "lessons learned" for Norway

We consider implications for regulation Norway in four stages, as described in Figure 17, below.

Figure 17. Sequential approach to drawing out key lessons for regulation in Norway

Source: Frontier Economics

In the first stage, we recap the key issues and concerns with regulation in Norway, as discussed in Chapter **Error! Reference source not found.**. In the econd stage, we define a number of evaluation criteria against which we assess lessons learnt from other countries. In stage three, we discuss what key lessons that can be drawn from other countries to address the issues identified in stage one, and then assess these key lessons against our evaluation criteria defined in stage two.

Each option for change will have its own pros and cons. The decision for any regulatory change will therefore involve some degree of subjective judgement, and will depend of the regulatory priorities identified at the time of change. The key tradeoffs associated with each option for change are discussed in stage four of our evaluation approach.

8.1.1 Stage 1: recap of key issues and concerns in Norway

As discussed in Chapter 3, there are five key areas of concern associated with regulation in Norway. These are summarised below.

- **First, costs based on accounting values** do not reflect economic costs very well. This is likely to result in an overestimation on efficiency scores in old networks and underestimation in new networks. Efficiency scores are likely to be biased by the stage of the network in the investment cycle.

- **Second, costs in the DEA benchmarking are based on a one-year reference period,** and are sensitive to the cost variations from one year to the next. Large investments in a particular year are likely to have a large impact on the efficiency scores of the companies.

- **Third, there are issues with the approach to benchmarking,** including the complexity of the DEA model, errors associated with the efficiency assessment, and the mechanistic application of efficiency scores to determine the final revenue cap.

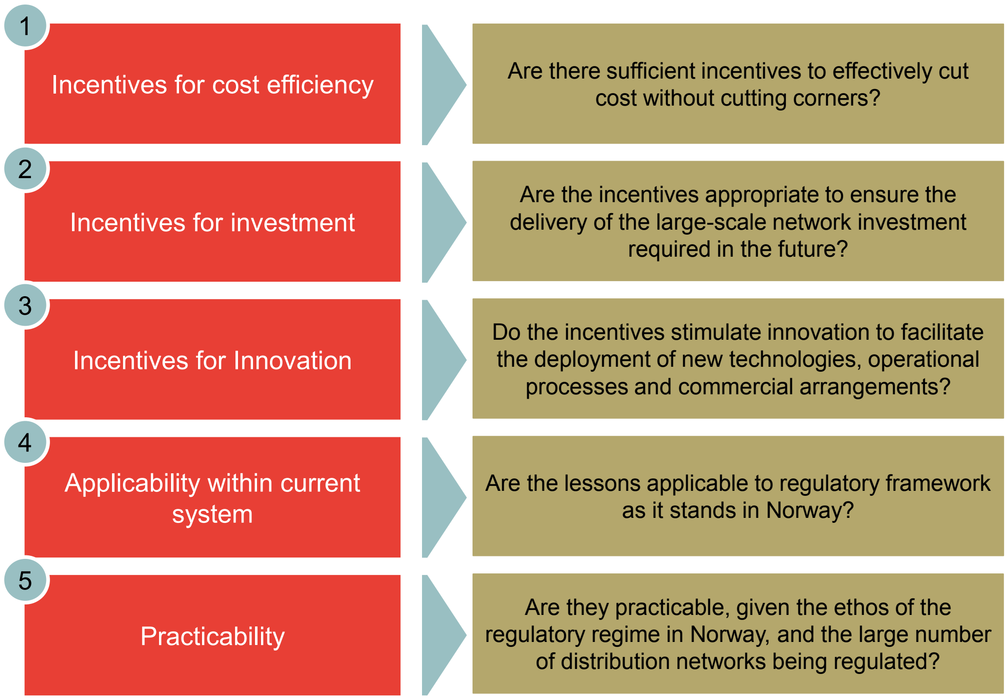
- **Fourth, there are concerns with the regional grid model,** including the treatment of large lumpy investments described above, and a need to assess the credibility of approaches to regulate the regional grid.

- **Finally, there is a need for greater investment and innovation incentives in general**, given the requirement for large-scale network investments going forward.

8.1.2 Stage 2: defining evaluation criteria

As described in Figure 18 below, we have defined five evaluation criteria against which we will assess the merits of the options that we describe in stage three.

Figure 18. Evaluation criteria



Source: Frontier Economics

Our five criteria are:

- incentives for cost efficiency;
- incentives for investment;
- incentives for innovation;
- applicability to the current regulatory regime as it stands in Norway; and
- practicability, given the large number of distribution networks in operation.

While not all five evaluation criteria will be applicable in assessing all of the options for change, the each option is discussed along these criteria where appropriate. The possible key tradeoffs associated with adopting each option are also discussed.

Before we consider implications for Norway from the case studies described in the preceding chapters, we highlight two key risks from mechanistically applying any lessons that can be learn from these countries on to the Norwegian regulatory regime as it stands.

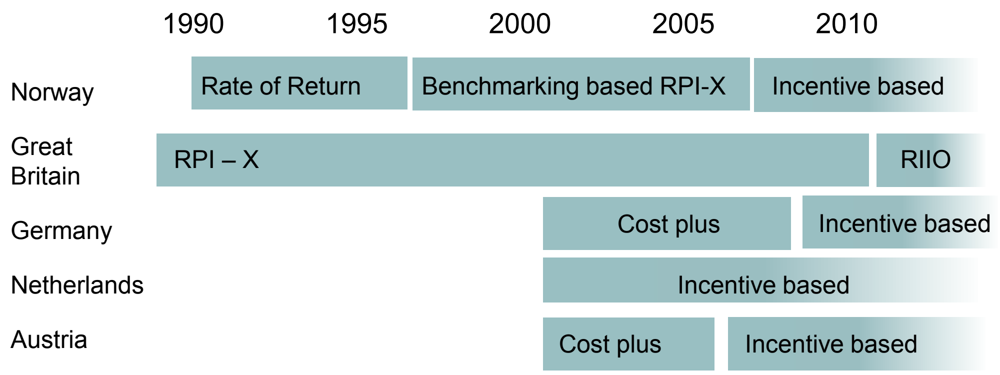
- First is the risk of drawing lessons from regulatory regimes that are less mature than the Norwegian regime.
- Second is the risk of comparing the Norwegian system to other industries that are structurally very different.

These are discussed below.

Maturity of the regulatory regimes

Figure 19 illustrates the evolution of the regulatory regimes in Norway, Germany, Austria, GB and the Netherlands.

Figure 19. Evolution of regulatory regimes



Source: Frontier Economics

The UK and Norway were amongst the first countries to implement market-oriented reforms of the electricity sectors, and have relatively evolved systems of regulation of natural monopoly segments. In GB, Ofgem has been applying incentive regulation since 1990. In Norway, NVE switched from rate of return to incentive regulation in 1997. Quality adjusted revenue caps were introduced in 2007.

On the other hand, the electricity markets in the Netherlands, Austria and Germany have introduced reforms more recently. The German and Austrian electricity markets were fully liberalised in 2001, and the Dutch markets liberalised in 2004. In Germany, BNetzA has applied cost plus regulation from 2001 to 2008, before switching to an incentive-based scheme in 2009. Similarly, in Austria, E-Contol has applied cost plus regulation from 2001 to 2005, before switching to an incentive-based scheme in 2006. In the Netherlands, incentive regulation has been applied since the first price control in 2001. Quality adjusted revenue caps were introduced in 2005. An implication of this is that the regulatory regimes in these countries are less mature than the Norwegian regime

Implications for Norway

itself. Therefore, any lessons learned from these countries need to be applied to Norway with caution, recognising that these regimes have not been in operation for as long as the Norwegian regime.

Structure of distribution industry

The second risk is of drawing lessons from countries that have a markedly smaller number of DSOs to Norway. The existence of a large number of distribution networks facilitates the use of relatively sophisticated benchmarking techniques such as DEA and SFA. These benchmarking techniques are used in Norway and Austria, which have over 150 DSOs, and Germany, which has around 800 DSOs. On the other hand, there are less than 15 distributions networks in both the Netherlands and GB, resulting in the evolution of regulatory frameworks that are remarkably different to those in existence in Norway. Again, lessons drawn from these countries need to be applied to Norway with caution.

In Section 8.2, we assess the options for change in Norway (stage three), and the key trade-offs associated with each (stage four).

8.2 Assessment of options for Norway

In this section, we will discuss the key lessons learned from our case studies to address the five key issues we identified to be relevant to regulation in Norway. We assess these key lessons against our evaluation criteria drawn out in stage two, and consider key tradeoffs.

8.2.1 Issue 1: Estimating capital costs using accounting values

The capital costs used to estimate annual allowed revenues in Norway are based on historic book values. We understand that NVE allowed companies to revalue their assets in 1997 using historic values and standardised depreciation periods. This was primarily done to create a level-playing field between the companies for the benchmarking analysis, and avoid distorting efficiency scores due to different accounting policies for depreciation. These are the costs that are currently used for regulatory reporting.

However, as historic book values do not reflect the current economic value of the assets in an appropriate way (they do not account for asset inflation over time, for example), they may distort the efficiency scores from the benchmarking analysis. This is likely to result in an overestimation of efficiency scores in old networks and underestimation in new networks.

From the case studies, this is a recognised issue, and we have identified a number of different ways standardising capital costs for the benchmarking analysis:

- **Approach A: Germany – Using annuities based on current costs:** In Germany, the benchmarking analysis is based on standardised capital costs using annuities. Annuities are designed to ensure fixed capex payments over a period of time. In order to calculate the annuities, the assets are revalued to their current costs by using asset inflation indices for different asset categories.

- **Approach B: Netherlands – Using indexed historic costs:** the Dutch regulator uses indexed historic costs (this is also called a current cost approach) to calculate the capital costs for the allowed revenues. This done by using a straight line depreciation methodology, and a WACC on residual values.

- **Approach C: Germany – Using best-of-approach:** the German regulator calculates efficiency scores using two approaches. The first is based on capital costs form companies' accounts, and the second is based on standardised values. The final company-specific efficiency factor is based on the best efficiency score from these two different model specifications.

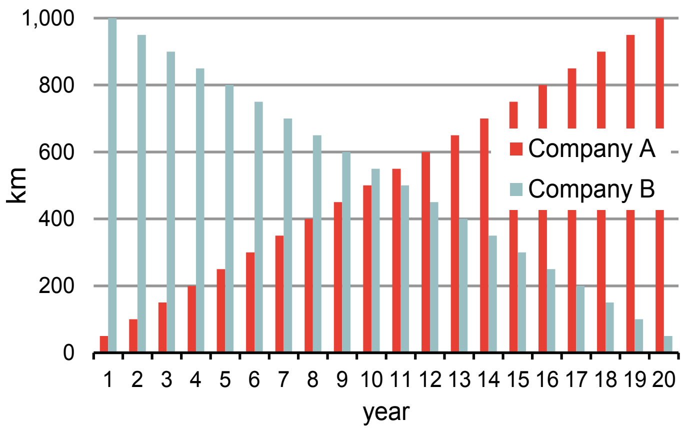
- **Approach D: UK – Using TOTEX approach:** In the next regulatory review in GB, Ofgem is planning to use a total expenditure (opex + capex + repex) approach instead of a total cost approach (based on a calculation of opex + depreciation + return). Totex benchmarking will be used alongside other techniques as a 'directional' tool or a starting point for assessing the company's forecasts, rather than as a mechanistic means of setting allowances.

Below, we discuss each of these options for change, alongside the five assessment criteria that we identified earlier. We also analyse the key tradeoffs that may be associated with adopting each option.

Approach A: "Using annuities based on current costs": assessment

Annuities based on current costs can be used in the benchmarking analysis to fully cancel out the impact of the investment cycle and cost increases of the assets over time on the capital costs. Figure 20 below illustrates two hypothetical companies with different investment cycles. Company A in this example has a relatively new network, when compared to Company B. By using annuities, both these companies would enter the benchmarking analysis with equal capital costs. Therefore, the systematic over-/underestimating of efficiency scores for old/new networks should diminish under this approach.

Figure 20. Investment cycle (km) for Company A ("new") and Company B ("old")



Source: Frontier

Below, we analyse this option for change against our five assessment criteria, and identify the key trade-off associated with implementing this change:

- *Incentive for cost efficiency* – annuitised capital costs under this approach would better reflect the economic costs of the assets, improving the overall quality of the benchmarking analysis. The results would better reflect the "true" cost efficiency, rather than other factors, such as the age of the network, that are not controllable by management decisions. Therefore, management decisions to improve the cost efficiency of the company will be better remunerated under this approach.

- *Incentive for investments* – the approach of using annuities has the benefit of removing the disincentive to invest in capex (relative to the use of historic costs in Norway) associated with the large adverse impact on efficiency scores in the year in which the capital expenditure is made. This approach would therefore create positive investment incentives. However, the adverse impact of any capex investment on efficiency scores will be averaged over long period of time. This may create an incentive for the networks to over-capitalise. Therefore, if there are any trade-offs between opex and capex, they may not be optimised under the use of annuities, as networks would be incentivised to replace their assets too early, rather than incurring maintenance costs, for example.

  In contrast, historic cost indexation (as in the Netherlands) leads to declining overall capital costs over the lifetime of the asset. The incentive to over-capitalise is lower under this approach than under the use of annuities, which would allow networks to better optimise their tradeoff between capex and opex over time.

- *Applicability to Norway* – using annuities in the benchmarking analysis does not require a fundamental change in the regulatory framework, and would therefore be applicable to the regime in Norway. However, adopting this approach would be a significant change in the treatment of capital costs.

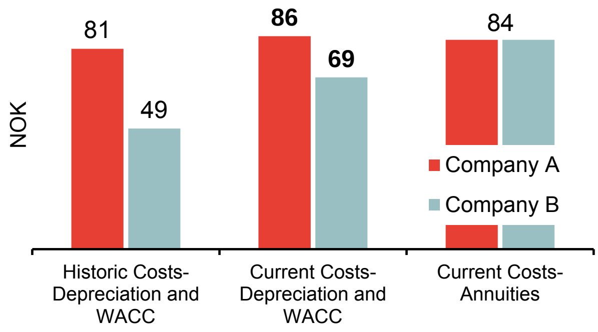
- *Practicability* – using annuities in the benchmarking analysis does not require a significant increase in the level of regulatory scrutiny. However, NVE would need to collect data from the companies on their historic annual investments grouped into different asset categories, and convert these to current costs values for the benchmarking analysis. It would also need to choose an index to convert from historic to current costs. This could be a consumer price index (CPI), retail price index (RPI), or another an index based on some other group of assets.

- *Main trade-off* – this approach has the benefit of creating more of a level-playing field for old and new networks in the benchmarking analysis, reducing the bias in favour of old networks from the use of historic costs. Also, investment incentives under this approach are strong. However, a disadvantage of this approach is that it may create an incentive for networks to over-capitalise, and trade-off capex solutions over opex ones. For example, networks may be incentivised to replace their networks too early, rather than incurring opex on maintenance.

Approach B: "Using indexed historic costs" – the Netherlands: assessment

In the Netherlands, capital costs for the benchmarking analysis are based on indexed historic costs. These are calculated using depreciation and WACC on residual value based on current costs asset values. This is another approach to reduce the impact of the investment cycle on the capital costs. Figure 21 illustrates an example of two hypothetical companies with different investment cycles (these investment cycles are illustrated in Figure 20 in the preceding section). Company A has a relatively new network compared to Company B. By using current costs, both companies will still enter the benchmarking analysis with different capital costs, but the difference will be reduced compared to when pure historic book values are used. In our illustrative example for company A and B, the difference reduces from NOK 32 (= 81-49) to NOK 17 (= 86-69). Therefore, the systematic over-/underestimating of efficiency scores for old/new networks will be reduced under the approach adopted in the Netherlands. Nevertheless, this bias could be reduced even further by using current cost annuities, as is done in Germany. Under this approach, the difference in the capital costs between the two companies would be NOK 0 (= 84-84).

Figure 21. Historic costs using depreciation and WACC, Current costs using depreciation and WACC and Current costs using annuities[11]



Source: Frontier

Below, we analyse this option for change against our five assessment criteria, and identify the key trade-off associated with implementing this change:

- *Incentive for cost efficiency* – Calculating capex based on indexed historic costs would better reflect the economic costs of the assets (by controlling for asset inflation), improving the overall quality of the benchmarking analysis. The results would better reflect the "true" cost efficiency, rather than other factors, such as the age of the network, that are not controllable by management decisions. Therefore, management decisions to improve the cost efficiency of the company will be better remunerated under this approach.

- *Incentive for investments* – historic cost indexation would amount to declining capital costs over the lifetime of the assets, rather than fixed capital costs in every year, as under the annuities approach. This approach has the benefit of reducing the bias in favour of old networks from the use of historic costs (as in Norway), to the extent that it adjusts for asset inflation over time, but to a lesser extent than under the annuities approach (as in Germany). Also, the incentive to spend on undesirable new capex, rather than incurring maintenance costs, would be lower under the use of indexed historic costs, relative to the annuities approach. Therefore, the trade-off between opex and capex may be better optimised under this approach, than under the use of annuities.

- *Applicability to Norway* – using a current cost approach to calculate capital costs for the benchmarking analysis does not require a fundamental

11 Investment costs/km in year 20 = 100 NOK, asset inflation = 2%pa, WACC (nom) = 7%, WACC (real) = 5%, Depreciation period = 20 years

change in the regulatory framework, and would therefore be applicable to the regime in Norway.

- *Practicability* – this approach does not require a significant increase in the level of regulatory scrutiny. However, NVE would need to collect data from the companies on their historic annual investments grouped into different asset categories, and convert these to current costs values for the benchmarking analysis. It would also need to choose an index to convert from historic to current costs. This could be a consumer price index (CPI), retail price index (RPI), or another an index based on some other group of assets.

- *Main trade-off* – this approach would create more of a level-playing field for old and new networks in the benchmarking analysis, by reducing the bias in the favour of old networks from the use of historic costs. While the age and investment cycle bias would be reduced to a greater extent by using annuities, annuities would not account for the opex/capex trade-off over time in the same way as under the historic cost indexation approach. The choice of the most appropriate approach to standardise costs would therefore depend on two factors. First is the size and impact of the actual bias associated with the age of the network. Second is the size of the trade-off between operating and capital expenditure, which depends extent to which maintenance costs are assumed to increase over time. However, as discussed under issue 3 below, we discuss the merits of using more than one approach in the calculation of allowed revenues.

Approach C: "Using best-of" - Germany: assessment

In the discussion above, we have identified a number of different approaches that can be used to standardise capital cost in order to create level-playing field for old and new networks. However, each of these approaches have their own drawbacks, and there would be trade-offs associated with adopting any of these options for change. In Germany, these trade-offs are overcome by adopting a benchmark that is based on a 'best of' two different approaches. The first is based on capital costs from companies' accounts, and the second is based on standardised values. The final company-specific efficiency factor is based on the best efficiency score from these two different model specifications.

A similar approach could be adopted in Norway by:

- calculating capital costs based on historic costs, current costs, and annuities from current costs;

- running the benchmarking analysis for each capital cost definition, and

- using the best efficiency result from the different benchmarking models.

Such an approach would increase the average efficiency for the all companies as:

Implications for Norway

- old networks would still benefit from the historic cost approach; and
- new networks would benefit from current cost approaches.

Below, we analyse this option for change against our five assessment criteria, and identify the key trade-off associated with implementing this change:

- *Incentive for cost efficiency* – Calculating capex based on annuities, as in Germany, or indexed historic costs, as in the Netherlands, would better reflect the economic costs of the assets, improving the overall quality of the benchmarking analysis. However, a best-of approach would select the model with the best efficiency score to set the revenue cap for each company. In other words old networks would still benefit from the model using historic costs, and new networks would simultaneously benefit from the use of annuities. Efficiency incentives under the 'best-of' approach are low, as the final benchmark is based on the model that makes the companies the most efficient.
- *Incentive for investments* – investment incentives under this approach, on the other hand, are high, as the best-of approach designed to ensure that companies meet and exceed their revenue targets.
- *Applicability to Norway* – using a 'best-of' approach does not require a fundamental change in the regulatory framework, and would therefore be applicable to the regime in Norway.
- *Practicability* – This approach would require a degree of increase in regulatory scrutiny, given its use of two models techniques, rather than one. Nevertheless, this would be feasible, given that it has successfully been demonstrated in the presence of a large number of DSOs in Germany.
- *Main trade-off* – this approach creates strong incentives for investments, as the revenue cap for the companies are based on the model which would give them the highest allowed revenues. However, efficiency incentives under this approach are low, as it could result in over-remuneration of network costs for poor performers and substantially reduce the discriminatory power of a benchmarking analysis and yardstick regulation.

Approach D: "Using totex approach" – GB: assessment

In GB, Ofgem uses a total expenditure (or totex) approach, where the cost base is calculated as the sum of opex, capex, and repex. This is used to overcome the issues associated with the calculation of depreciation, RAB and WACC under the total cost approach (where the cost base is calculated as the sum of opex + depreciation + return) used in Norway, Germany, Austria and the Netherlands.

One of the main drawbacks of the totex approach, however, is the lumpy nature of capex. Large one-off investments would have a large adverse impact on efficiency scores in the year in which they are incurred, distorting incentives for investment. To overcome this issue, Ofgem proposes to use moving averages for capital costs over a long time period.

Below, we analyse this option for change against our five assessment criteria, and identify the key trade-off associated with implementing this change:

- *Incentive for cost efficiency* – smoothing large capital investments over a long time frame by using moving averages, would help reduce the age and investment cycle bias associated with capitalisation assumptions that need to be made under the total cost approach adopted in Norway. The totex approach is not sensitive to the assumptions used to calculate depreciation, RAB and WACC. This approach has a positive effect on efficiency incentives, as the age bias associated with the total cost approach used in the Netherlands is reduced.
- *Incentive for investments* – Investment incentives under this approach are high, as the impact of large one-off investments is averaged over time (therefore reducing the adverse impact on efficiency scores in the year in which the expenditure is incurred).
- *Applicability to Norway* – using a Totex approach would require a fundamental change in the regulatory framework in Norway. The current system of yardstick regulation in Norway is based on a total cost approach in which the cost base is defined as a sum of opex, depreciation and return. The total expenditure or totex approach in GB, on the other hand, is built on a cost base which is calculated as a sum of actual opex, capex and repex. The totex approach proposed by Ofgem for the next regulatory period is also one that has not been tested in the GB in actual practice.
- *Practicability* – using a totex approach would not require a significant increase in the level of regulatory scrutiny adopted by the regulator. However, adopting this approach would require a fundamental overhaul of the regulatory regime in Norway.
- *Main trade-off* – this approach improves incentives for efficiency, as its results would be less sensitive to the age of the network, which is not controllable by management decisions. Investment incentives under this approach are also high, as the impact of large one-off investments is averaged over time (therefore reducing the adverse impact on efficiency scores in the year in which the expenditure is incurred). The main drawback of adopting this approach is that it would require a fundamental overhaul of the regulatory regime as it stands in Norway.

Implications for Norway

Furthermore, this is an approach that has not been tested in GB in actual practice.

Summary and key recommendations

In this Section, we have discussed the issues associated with the use of historic cost accounting in Norway. The capital costs used to estimate annual allowed revenues in Norway are based on historic book values. As historic book values do not reflect the current economic value of the assets in an appropriate way, they may distort the efficiency scores from the benchmarking analysis. A concern here is that this is likely to result in an overestimation of efficiency scores in old networks and underestimation in new networks. From our case studies, we understand that this is a recognised issue across Europe, and have identified a number of different ways standardising capital costs for the benchmarking analysis. These are by:

- **Using annuities on current cost values, as in Germany**, would ensure fixed capex payments over the lifetime of the asset, reducing the impact of the investment cycle on efficiency scores. This approach has the benefit of creating more of a level-playing field for old and new networks in the benchmarking analysis, reducing the bias in favour of old networks from the use of historic costs (as in Norway). However, a drawback of this approach is that it may incentivise all networks to over-capitalise, as the adverse impact of any capex investment on efficiency scores will be averaged over a long period of time, rather than being observed in the year in which the expenditure is incurred. Therefore, if there are trade-offs between opex and capex, they may not be optimised under the use of annuities, as networks would be incentivised to replace their assets too early, rather than incurring maintenance costs, for example.

- **Using indexed historic costs (also known as current costs), as in the Netherlands**, capital costs would be based on a straight line depreciation methodology, and a WACC on residual values. This would amount to declining capital costs over the lifetime of the assets, rather than fixed capital costs in every year, as under the annuities approach. This approach has the benefit of reducing the bias in favour of old networks from the use of historic costs (as in Norway), to the extent that it adjusts for asset inflation over time, but to a lesser extent than under the annuities approach (as in Germany). Also, the incentive to spend on undesirable new capex, rather than incurring maintenance costs, would be lower under the use of indexed historic costs, relative to the annuities approach. Therefore, the trade-off between opex and capex may be better optimised under this approach, than under the use of annuities.

- **Using a 'best-of' approach, as in Germany**, is one way of testing for the impact of different ways of standardising assets. The German regulator calculates efficiency scores using two approaches. The first is based on capital costs from companies' accounts, and the second is based on standardised values (using annuities on current costs). The final company-specific efficiency factor is based on the best efficiency score from these two different model specifications. This approach would have the benefit of creating strong incentives for investments, as the revenue cap for the companies is based on the model which would afford them the highest allowed revenues. However, efficiency incentives under this approach would be low, as it could result in the over-remuneration of network costs for poor performers, and substantially reduce the discriminatory power of a benchmarking analysis and yardstick regulation.

- **Using a total expenditure (or totex) approach, as proposed in GB**, would be an alternative way of overcoming the issues associated with the accounting treatment of capex. Under this approach, the cost base is calculated as the sum of opex, capex, and repex. This is used to overcome the issues associated with the calculation of depreciation, RAB and WACC under the total cost approach (where the cost base is calculated as the sum of opex + depreciation + return) used in Norway, Germany, Austria and the Netherlands. One of the main drawbacks of the totex approach, however, is the lumpy nature of capex. Large one-off investments would have a large adverse impact on efficiency scores in the year in which they are incurred, distorting incentives for investment. To overcome this issue, Ofgem proposes to use moving averages for capital costs over a long time period. The main drawback of this approach is that it would require a fundamental overhaul of the regulatory regime as it stands in Norway, and that it has not yet been tested in actual practice in GB.

We recommend testing the impact of using different ways of standardising capital costs, as is done in Germany. As using a 'best-of' approach may result in the over-remuneration of networks, and may have adverse efficiency incentives, we discuss an alternative way of translating these different benchmarking results into a final revenue cap under issue 3, below. Although it has some attractions, the totex approach proposed by Ofgem for the next regulatory period would require a fundamental overhaul of the regulatory regime in Norway. Furthermore, given that this is also an approach that has not been tested in the GB in actual practice, we do not consider it to be suitable for Norway, as yet.

8.2.2 Issue 2: Using a one year reference period

The costs used for setting the annual allowed revenues and conducting the annual benchmarking analysis in Norway are based on a one year reference period. Therefore, the benchmarking results in Norway are sensitive to cost variations from one year to the next in the following respects.

- **Lumpy extension and replacement investment:** Capital and replacement expenditure are lumpy by nature, and vary to a large extent from year to year.

- **Variation in pension allowances from year to year:** Pension costs also tend to be lumpy and volatile. Large pension payments need to be incurred in instances of change in corporate control, or corporate activity within the network company's wider group. They are also, to a large extent, driven by legal requirements. The profile of these costs is influenced primarily by the age of the workforce within the firm, and is generally outside of management control.

- **Atypical costs:** Other costs may be atypical and lumpy, due to severe weather conditions, for example.

From our case studies, we have identified a number of different options to account for the issue of cost variations from year to year, and their impact on allowed revenues.

  - **Approach A: GB – Excluding pension costs from benchmarking:** in GB, pension costs are excluded from the cost base used to benchmark performance. To account for pension costs, a separate adjustment is made to the RAB. The impact of the pension costs is phased into the RAB over a certain period. Unexpected deficit payments which tend to occur in instances of change in corporate control, or through corporate activity within the network company's wider group are planned to be phased in over 15 years under RIIO.

  - **Approach B: Austria – adjusting for pension costs through separate adjustments in the RAB** - the Austrian regulator accounts for companies' different treatment of pension allowances by adjusting the cost of capital by the so called "Finanzierungskomponente". As a result, the different treatment of pension allowances has no impact on the benchmarking results.

  - **Approach C: Germany, Austria – Normalisation of one-off expenses over certain time period:** Bundesnetzagentur and E-Control normalise some atypical one-off expenses over a number of years to smooth out their cost and revenue effects in the benchmarking analysis. However, there are no explicit rules to determine when and how this normalisation is done.

  - **Approach D: UK – Using averages for costs:** In GB, Ofgem uses a total expenditure (or totex) approach, wherein the cost base is calculated as the sum of opex, capex, and repex. In order to smooth out the impact of large, one-off capex investments on efficiency scores, long-term moving averages are used.

Given that we have already discussed the use of long-term averages in section 8.2.1 above, this section will analyse the options of excluding of pension costs from the benchmarking, as is done GB, of making separate adjustments to the RAB, as is done in Austria, and normalising one-off expenses, as is done in Germany and Austria.

Below, we discuss each of these options for change, alongside the five assessment criteria that we identified earlier. We also analyse the key tradeoffs that may be associated with adopting each option.

Approach A: "Excluding pension costs from efficiency benchmarking" – GB: assessment

In GB, Ofgem reduces the impact of year-on-year cost variations from pension by excluding them from the benchmarking analysis altogether.

Below, we analyse this option for change against our five assessment criteria, and identify the key trade-off associated with implementing this change:

- *Incentive for cost efficiency* – year-on year variations in pension costs that are largely out of management control (to the extent that they depend on the age of the workforce and management decisions that may have been made in the past) and could distort efficiency scores, if included in the benchmarking. Excluding these costs from the benchmarking analysis would help reduce the volatility in allowed revenues, making them more reflective of managerial efficiency. On the other hand, by directly passing through these costs, the regulator may create an incentive for companies to implement overgenerous pension schemes for their employees, at the expense of increasing costs for customers. This may be argued if it is believed that the management can influence the level of pension costs to a larger extent that the profile of these costs. This risk of over-compensation, however, could be mitigated by appropriately designing the pension adjustment (by setting separate allowances in line with competitive benchmarks, for example) that is made to the RAB.
- *Incentive for investments* – excluding a large, one-off cost items from the benchmarking would reduce the annual volatility of allowed revenues, increasing the planning security for companies and investors, and improving incentives for investments.
- *Applicability to Norway* – Excluding pension costs from benchmarking analysis would not require a fundamental change in the regulatory

framework. This approach could, therefore, be applied to the Norwegian regime.

- *Practicability* – this approach would not require a significant increase in the required level of regulatory scrutiny. However, the regulator may decide not to exclude all pension costs but only statutory costs to keep incentives for cost efficiency at high levels. Making this distinction between voluntary and statutory costs may slightly increase the required level of regulatory scrutiny.

- *Main trade-off* – defining pension costs as a cost-pass-through item would help reduce the volatility in annual revenues, and thereby create greater certainty for investors. Incentives for efficiency would also increase as a result of excluding costs from the benchmarking that are lumpy, and the profile of which is largely out of management control. On the other hand, directly passing though pension costs may create incentives for companies to implement overgenerous pension schemes for their employees. This risk, however, could be mitigated by appropriately designing the pension adjustment that is made to the RAB.

Approach B: "Adjusting for pension costs through separate adjustments in the RAB" – Austria: assessment

In Austria, pension costs are sensitive to the different accounting principles adopted by different companies. While some companies report their pension costs at EBIT (Earnings before interest and tax), others report them after Ebit. Pension allowances before Ebit lead to higher costs in the benchmarking analysis. E-Control controls for the effect of different pension allowances by adjusting the cost of capital by a "Finanzierungskomponente".

Below, we analyse this option for change against our five assessment criteria, and identify the key trade-off associated with implementing this change:

- *Incentive for cost efficiency* – as this is an ex-post adjustment, efficiency incentives will still be distorted by differences in accounting treatments of pension costs. To help facilitate comparisons on a more like-for-like basis and improve incentives for firms to be efficient, it would be more effective to adjust for these costs before they enter the benchmarking analysis.

- *Incentive for investments* – incentives for investment will be less distorted by differences in accounting treatments between companies (as these are adjusted for in the RAB).

- *Applicability to Norway* – this approach would not require a fundamental change in the regulatory framework, and could therefore be applied to the Norwegian regime.

- *Practicability* – this approach would not require a significant increase in the required level of regulatory scrutiny.
- *Main trade-off* – this approach would be helpful in reducing the distortion in investment incentives associated with differences in the treatment of pension costs between companies. However, as this is an ex-post adjustment, efficiency incentives will still be distorted by such differences. To help facilitate comparisons on a more like-for-like basis and improve incentives for firms to be efficient, it would be more effective to adjust these costs for heterogeneous accounting policies before they enter the benchmarking analysis.

Approach C: "Normalisation of one-off expenses" - Germany and Austria: assessment

In Germany and Austria, the adverse impact of atypical lumpy, one-off costs on benchmarking is reduced by normalising these costs over a number of years before including them in the benchmarking analysis for setting allowed revenues. However, this normalisation is not governed by any defined rules, and is often based on the discretion of the regulator.

Below, we analyse this option for change against our five assessment criteria, and identify the key trade-off associated with implementing this change:

- *Incentive for cost efficiency* – this approach, in principle, would increase the incentive for cost efficiency. The impact of one-off expenses which are largely outside the control of the management, on the efficiency results, would be mitigated by way of normalisation. However, given that this type of normalisation is based on the discretion of the regulator, the extent to which it is effective will depend on the way in which it is designed. For example, it would not be suitable to normalise costs that may have already been normalised over time through the allowance for depreciation.
- *Incentive for investments* – excluding a large, one-off cost items from the benchmarking would reduce the annual volatility of allowed revenues, increase the planning security for companies and investors, and improve incentives for investment. However, the element of regulatory discretion associated with this approach would increase regulatory risk and uncertainty, thereby reducing the incentives for investments.
- *Applicability to Norway* – Normalisation of one-off expenses does not require a fundamental change in the regulatory framework. However, the high level of regulatory discretion associated with this approach creates a risk that it may not be applied in a suitable way.

- *Practicability* – this approach would require an increase in the level of regulatory scrutiny. To reduce the risk of regulatory discretion, transparent rules regarding what a "one-off" expense is, and over which period it should be normalised, would need to be developed by NVE.

  Main trade-off – this approach has a benefit of reducing the volatility in annual revenues from lumpy expenses, by phasing in the expenses over several years. However, given that this approach is not governed by any defined rules, and is often based on the discretion of the regulator, it is associated with a large degree of regulatory risk and uncertainty.

Summary and key recommendations

In this section, we have discussed the issue of setting the annual allowed revenues, and conducting the annual benchmarking analysis in Norway, on costs that are based on a one-year reference period. NVE sets its annual allowed revenues, and conducts its annual benchmarking analysis in Norway, using costs that are based on a one-year reference period. From our discussions with Energy Norway, we understand that a drawback of this approach is that the benchmarking analysis conducted by NVE is sensitive to cost variations from one year to another due to lumpy extension and replacement investments, and also because of pension costs that are largely outside of management control.

From our case studies, we have identified a number of different options to account for the issue of cost variations from year to year, and their impact on allowed revenues.

- **By excluding pension costs from the benchmarking, as in GB**, volatility in annual revenues could be reduced, creating greater certainty for investors. Incentives for efficiency would also increase as a result of excluding costs from the benchmarking that are lumpy, and the profile of which is largely out of management control (to the extent that they depend on the age of the workforce and management decisions that may have been made in the past). On the other hand, directly passing though pension costs may create incentives for companies to implement overgenerous pension schemes for their employees. This may be argued to be the case if the management can influence the level of pension costs to a larger extent that the profile of these costs. This risk, however, could be mitigated by appropriately designing (by setting separate allowances in line with competitive benchmarks, for example) the pension adjustment that is made to the RAB.

- **By adjusting for the different accounting treatments of these pension costs in the RAB, as in Austria**, revenue allowances are less distorted by differences in the treatment of pension costs between companies. However, as this is an ex-post adjustment, efficiency incentives will still be distorted by such differences. To help facilitate comparisons on a more like-for-like basis and improve incentives for firms to be efficient, it would be more effective to adjust these costs for heterogeneous accounting policies before they enter the benchmarking analysis.

- **By normalising large one-off expenses over a longer time-period, as in Germany and Austria**, volatility in annual revenues could be reduced, creating greater certainty for investors. However, given that this approach is not governed by any defined rules, and is often based on the discretion of the regulator, it is associated with a large degree of regulatory risk and uncertainty.

- **By using long-term moving averages, as in GB,** Ofgem reduces the adverse impact of large, one-off capex investments on efficiency scores in the year in which they are incurred. This approach reduces the volatility in annual revenues, creating greater certainty for investors. However, as with the normalisation of costs in Germany and Austria, a drawback of this approach is the "lagged inefficiency" effect on revenue caps in any year.

We consider two broad types of approaches to be applicable for Norway. First is the exclusion of expenses that are either lumpy or outside of management control from the efficiency benchmarking, provided that these expenses are appropriately adjusted for in the RAB. Second is the use of long-term averages, provided that there are explicit rules to govern which costs are normalised, and under what circumstances. However, as there are tradeoffs associated with both these options, they would need to be implemented with caution. Furthermore, we suggest that any costs that are subject to heterogeneous accounting policies be adjusted for before they enter the benchmarking analysis.

8.2.3 Issue 3: Issues with DEA

There are three main issues with the approach to DEA benchmarking adopted by NVE. These are discussed below.

- **First, the model adopted by the NVE is highly complex.**
  - The DEA model in Norway includes a large number of parameters (8 outputs in total); also
  - It is subject to a large number of ex-post adjustments (including the correction for environmental factors in stage 2 and the calibration in stage 3).

  Furthermore, the large number of outputs in the DEA model may lead to an overestimation of efficiency scores for the industry as a whole. These overestimated efficiencies feed into the calibration of the yardstick.

- **Second, there are a number of errors associated with the efficiency assessment.** NVE uses only one model specification to calculate efficiency scores for companies. The resulting DEA efficiency scores are subject to:
  - noise in the data which may be classified as inefficiency; and
  - outlier companies with unique output/input relations, which may not serve as appropriate benchmarks.
- **Finally, the efficiency scores from the DEA analysis are mechanistically used to calculate allowed revenues.** Revenue caps are mechanistically set on the basis of the formula:

$$Revenue\ Cap = Cost\ Norm * \ \rho + Cost\ Base * (1 - \ \rho)$$

  This is in recognition of the fact that DEA efficiency scores may be subject to errors, to account for which, only 60% of the revenue cap is mechanistically based on the 'cost norm' (as ρ is currently set to 0.6).

From our case studies, we have identified a number of different options to improve NVE's benchmarking analysis, and its calculation of allowed revenues.

- **Approach A: reducing the number of outputs in the DEA modelling, as in Germany**- Germany and Austria include all environmental factors in the DEA model (and hence have fewer adjustments). Furthermore, the German regulator has proposed to reduce the number of outputs in the DEA model in the next price control to reduce its level of complexity. However, other elements of the price control remain relatively complex (for example, the expansion factor in Germany)
- **Approach B: 'toolkit' approach used in GB** - Benchmarking in GB is based on a 'toolkit' of approaches. This is implemented in combination with a number of other elements of the price control (including an output-focus and well-justified business plans), which are relatively complex and require a high degree of regulatory involvement. The resulting efficiency scores are not translated mechanistically into revenue caps, but, instead, are subject to a degree of regulatory judgement.
- **Approach C: light-touch approach used in the Netherlands** – Benchmarking in the Netherlands is based on a relatively simplistic total factor productivity (TFP) approach. However, the small number of DSOs in the Netherlands means that there are potentially fewer differences to control for.
- **Approach D: using two different modelling techniques, as in Germany and Austria** – DEA and SFA are used as two alternative techniques to

benchmark costs in Germany, and DEA and MOLS are used in Austria. There are a number of different ways to use these modelling results to set revenue caps. In Germany, the revenue cap for each of the companies is set to the best result from the different model specifications (or the one that renders the company the most efficient). In Austria, the revenue cap for each of the companies is set to a weighted average of the results from the two models. Finally, the regulator could also apply a filter to mechanistically use the benchmarking results only when it would be appropriate to do so. For example, the regulator could use an average of the results from the two models, except in cases where they are drastically different, when greater regulatory scrutiny could be applied.

- **Approach E: using the outlier detection techniques adopted in Germany** – Outliers in the DEA analysis are detected using 'super-efficiencies' and peer analysis.

Below, we discuss each of these options for change, alongside the five assessment criteria that we identified earlier. We also analyse the key tradeoffs that may be associated with adopting each option.

Approach A: reducing the number of outputs in the DEA modelling: assessment

As is already being considered by NVE, there is scope to reduce the number of outputs in the DEA analysis, and test whether these are statistically significant in the second stage regression analysis.

Below, we analyse this option for change against our five assessment criteria, and identify the key trade-off associated with implementing this change:

- *Incentive for cost efficiency* – a reduction in the number of outputs in the DEA analysis should reduce the overestimation of efficiency scores. Furthermore, by including more outputs in the regression analysis in stage two, it would be possible to test for and include only those outputs in the model that have a statistically significant impact on estimated efficiencies.
- *Incentive for investments* – the impact on investment incentives is uncertain, and would depend on the final model specification adopted by the regulator.
- *Applicability to Norway* – this approach would appear not to require a fundamental change in the regulatory framework, and would therefore be applicable to the regime in Norway.
- *Practicability* – reducing the number of outputs in the DEA model would not require a big increase in the level of regulatory scrutiny. However,

more statistical testing would be required in stage two of the regression analysis.

- *Main trade-off* – the existence of a large number of heterogeneous DSOs in Norway, creates a large number of factors that need to be controlled for in NVE's model, if comparisons are to be made on a like-for-like basis. This makes NVE's model highly complex, as it includes a large number of outputs and adjustments. Moving some of the outputs from the DEA analysis to the regression analysis would lower the overestimation of efficiency scores, and enable statistical testing. However, the model would still remain inherently complex, including the same total number of outputs and adjustments as before. Therefore, while this approach would help reduce the number of errors in the DEA model, it would not reduce the overall level of modelling complexity.

Approach B: 'toolkit' approach used GB: assessment

Model complexity in the UK is reduced by adopting a toolkit of relatively simple approaches, each of which is used to cross-check the other. For example, techniques in the toolkit include unit-cost benchmarking, trend analysis and OLS regression analysis. This is implemented in combination with a number of other elements of the price control (including an output-focus and well-justified business plans), which are relatively complex and require a high degree of regulatory involvement. The resulting efficiency scores are not translated mechanistically into revenue caps, and instead are subject to a degree of regulatory judgement.

Below, we analyse this option for change against our five assessment criteria, and identify the key trade-off associated with implementing this change:

- *Incentive for cost efficiency* – Incentives for cost efficiency will be higher under this approach, as companies will not have the incentive to adjust their business plans to perform well in just one type of assessment. Sensitivity analysis ensures that the results from any one assessment can be cross checked with at least one other. It also reduces the reliance of the revenue cap on any single model. Regulatory judgement and scrutiny is exercised in an effort to ensure that the chosen benchmarks are the most appropriate.

- *Incentive for investments* – Well-justified business planning is used to ensure that costs are not removed from the business at the expense of outputs. Incentives for investment are also facilitated by the emphasis on output delivery and longer-term planning. For example, in GB, Ofgem would allow spend in the current period that improved output delivery in future periods, if companies were able to demonstrate a clear link between costs now and savings in the future.

- *Applicability to Norway* – This approach would require a fundamental change in the regulatory framework as it currently exists in Norway. The 'toolkit' approach used in the UK relies on a great degree of regulatory judgement and scrutiny. Furthermore, its application is combined with a number of other revolutionary elements to the price control, such as an output-focus and well-justified business planning, which would require a fundamental regulatory overhaul to be implemented in Norway.

- *Practicability* – Adopting a 'toolkit' approach to benchmarking in Norway would require a significant increase in the degree of regulatory scrutiny and judgement on the part of the regulator, which would not be practicable, given the large number of DSOs. For example, its application is linked with the submission of well-justified business plans by the DSOs, each of which is assessed on a case-by-case basis by the regulator in order to determine the extent and type of benchmarking that would be necessary. While this is an effective way to assess the performance of

- *Main trade-off* – Adopting a toolkit approach would reduce model complexity, errors in the modelling, and overcome the problem of the mechanistic application of benchmarking as it is done in Norway. However, this approach would be intensive in terms of regulatory input, which would be potentially infeasible in a system with a large number of DSOs.

Approach C: light-touch approach used in the Netherlands: assessment

Benchmarking in the Netherlands is based on a 'light-touch' total factor productivity (TFP) approach. While this approach is feasible given the small number of DSOs in the Netherlands, and potentially fewer differences to control for, it may not be applicable to Norway, given its large number of DSOs.

Below, we analyse this option for change against our five assessment criteria, and identify the key trade-off associated with implementing this change:

- *Incentive for cost efficiency* – A light-touch approach would reduce model complexity. Its results would therefore be more transparent and easier to understand. Incentives for cost efficiency, may, however, be low under such an approach, as it would potentially not control for all factors affecting performance. The resulting benchmarks, May therefore, be somewhat arbitrary.

- *Incentive for investments* – The impact on investment incentives is uncertain, and would depend on the final model specification adopted by the regulator.

- *Applicability to Norway* – This approach would require a fundamental change in the regulatory framework as it currently exists in Norway. Furthermore, applying a light-touch approach in Norway would create the risk of not controlling for the large number of differences that exist between the 150 DSOs in operation. We therefore do not consider this approach to be applicable to Norway.
- *Practicability* – While this approach would facilitate a reduction in the level of regulatory scrutiny, we do not consider it to be practicable given that it would not successfully control the differences between all the DSOs in Norway.
- *Main trade-off* – A light touch approach y. However, there is the risk that the differences between the companies would be missed. This could result in the need to be more generous (potentially in an arbitrary manner) elsewhere in the settlement. We therefore do not consider this approach to be applicable to Norway.

Approach D: using two different modelling techniques: assessment

Using two alternative modelling techniques rather than just one is an effective way of cross-checking benchmarking results. If the two models provide drastically different results, it is an indication that the results could be driven by the specification of these models, rather than the actual performance of the companies. Furthermore, while DEA has its merits in not assuming any particular functional form, and identifying the most appropriate peers for companies, other modelling techniques have their own advantages. For example, while DEA assumes that all the differences between companies are a result of inefficiency, SFA is able to distinguish between this inefficiency, and noise in the data (attributable to measurement error and factors excluded from the modelling). Similarly, both SFA and MOLS facilitate the statistical testing of the impact of different drivers of costs, which is not possible using DEA. From our discussions with Energy Norway, we understand that NVE is investigating the use of SFA in future price controls.

Once we have our results from these models, there are a number of different ways of using them to set the final revenue cap for each company. In Norway, DEA efficiency scores are mechanistically translated into revenue caps. We this there are a number of options for change based on our case studies.

- **Option A: The first option is the use of a 'best-of' approach.** The German regulator tests the sensitivity of the benchmarking results to two alternative modelling techniques (DEA and SFA) and two alternative cost bases (actual and standardised). The revenue cap for each of the companies is set to the best result from the four different model specifications (or the one that renders the company the most efficient).

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- **Option B: The second is the use of weighted averages.** The Austrian regulator tests the sensitivity of the benchmarking results to two alternative modelling techniques (DEA and MOLS). The revenue cap for each of the companies is set to a weighted average of the results from the two models.

- **Option C: Finally, NVE may also consider a third option of mechanistically applying regulatory judgment, where appropriate.** For example, NVE could use the average result from two different models to set its revenue cap, except in cases where these results are drastically different from one another (say, where the difference is greater than 20%). In cases where the two models provide similar results, there is evidence that they support each other's findings, and could be averaged to set revenue caps On the other hand, in cases where the two models lead to very different results, it would be more appropriate investigate what drives these differences, rather than using an average or a 'best-of' the two results, given these may be driven by the model specification or the definition of the underlying costs, rather than actual drivers of company performance.

Below, we analyse this option for change, and the different ways in which it can be implemented, against our five assessment criteria. We also identify the key trade-off associated with implementing this change:

- *Incentive for cost efficiency* – by using different model specifications, companies will not have the incentive to adjust their business plans to perform well in just one type of assessment. Sensitivity analysis ensures that the results from any one assessment can be cross checked with the other. However, the efficiency incentives from the approach will depend on how it is used to set benchmarks. We consider a number of different options.

  First, if revenue caps are set by using a "best-of" approach, incentives for efficiency will be low, as the targets for the companies will be set based the model that favours them the most. "Best-of" approaches are designed to ensure that companies meet and surpass their targets. This may result in an over-remuneration of network costs.

  Second, the use of a weighted average approach, rather than a 'best-of' approach, may provide a more fair balance between companies and customers.

  Third, NVE could explore creating a filter to mechanistically apply regulatory judgement only where appropriate. For example, NVE could use the average result from two different models to set its revenue cap, except in cases where these results are drastically different from one another (say, where the difference is greater than 20%). Such an approach would minimise the extent of over-remuneration of networks. The threat of greater regulatory scrutiny in cases where the model specifications lead to drastically different results would create strong efficiency incentives.

- *Incentive for investments* – by using sensitivity analysis, incentives for investment will be less distorted by errors in the efficiency benchmarking, but will depend on how these models are used to set benchmarks. Investment incentives will be highest under the best-of approach, as it is designed to ensure that companies meet and exceed their revenue targets. It is uncertain whether incentives for investment will be higher under a weighted averages approach (or with a rule to mechanistically apply regulatory judgement), relative to the current model adopted by NVE, and will depend on whether or not the additional model used by NVE would favour the company.
- *Applicability to Norway* – This approach would not require a fundamental change in the regulatory framework, and would therefore be applicable to the regime in Norway.
- *Practicability* – This approach would require a degree of increase in regulatory scrutiny, given its use of two benchmarking techniques, rather than one. Nevertheless, this would be feasible, given that it has successfully been demonstrated in the presence of a large number of DSOs in both Germany and Austria. However, the required level of increase in scrutiny would be particularly high if NVE considers the option of mechanistically applying (in certain cases) regulatory judgment, where appropriate.
- *Main trade-off* – Multiple modelling techniques are useful to test the sensitivity of the benchmarking results to the choice of inputs, outputs and functional form. However, there is a risk that sensitivities introduce ambiguity in the results and increase the scope for regulatory lobbying. Multiple models may also increase the level of complexity involved in the benchmarking exercise.

  Incentives for efficiency and investment would depend on how these multiple model specifications are used to set the revenue caps. The 'best-of' approach creates the strongest incentives for investments, as the revenue cap for the companies are based on the model which would give them the highest allowed revenues. However, efficiency incentives under this approach are low.

  A weighted average approach would provide more of a balance between efficiency and investment incentives, when compared to the 'best-of' approach. However, there may be a great deal of ambiguity in instances when the results from the two models are drastically different, which would create scope for regulatory lobbying to determine how much weight should be attached to each of the models.

As an alternative, the regulator could also apply a filter to mechanistically use the benchmarking results only when it would be appropriate to do so. For example, the regulator could use an average of the results from the two models, except in cases where they are drastically different (when the difference between the efficiency scores is greater than 20%, for example), when greater regulatory scrutiny could be applied. A benefit of this approach is that strikes a good balance between the use of mechanistic rules (when there is confidence in the results) and the application of regulatory judgement (when the results are more ambiguous).

Approach E: Using the outlier detection techniques: assessment

Outliers in the DEA analysis are detected using two methods in Germany:

- 'Super-efficiency' analysis is used to distinguish between the efficiency scores of the firms that are on the efficiency frontier. This allows for efficiency scores that are greater than 100%. In Germany, companies that exceed a certain threshold of efficiency are considered to have unique input-output relationships, and are deemed to be outliers.

- 'Peer analysis' is another technique used to identify outliers in Germany. If companies are on the frontier, and appear to be the most efficient peers for a very large number of other firms, they are considered to have unique input-output relationships, and are deemed to be outliers.

Outlier analysis is a means of reducing the errors associated with the DEA benchmarking conducted by NVE. While NVE is currently using 'super-efficiency' analysis to identify for outliers, peer-analysis could also be considered as a complementary tool.

Below, we analyse this option for change against our five assessment criteria. We also identify the key trade-off associated with implementing this change:

- *Incentive for cost efficiency* – Incentives for cost efficiency will be higher under this approach, as they will be less subject to errors in the DEA modelling. Furthermore, distinguishing between companies on the efficiency frontier would increase efficiency incentives even further, as companies are allowed to be super-efficient.

- *Incentive for investments* – Incentives for investment will be less distorted by errors in the efficiency benchmarking.

- *Applicability to Norway* – This approach would not require a fundamental change in the regulatory framework, and would therefore be easily applicable to the regime in Norway.

- *Practicability* – This approach would require only a minor degree of increase in regulatory scrutiny, and would therefore be practicable for Norway.
- *Main trade-off* –Adopting the peer-analysis approach as a complimentary tool to the super-efficiency analysis conducted by NVE would be an effective way to account for some of the errors in the DEA benchmarking. This is an easy win, as it does not require a great deal of increase in regulatory burden.

Summary and key recommendations

In this section, we have discussed the issues with NVE's benchmarking analysis, including the complexity of the DEA model, errors associated with the efficiency assessment, and the mechanistic application of efficiency scores to determine the final revenue cap.

We have identified a number of different options to improve NVE's benchmarking analysis from our case studies.

- **By reducing the number of outputs in the DEA modelling, as in Germany**, and moving these to stage two of the regression analysis, NVE could lower the overestimation of efficiency scores associated with the large number of explanatory variables in DEA, and enable statistical testing.

- **By adopting a toolkit approach, as in GB**, NVE could sense-check its DEA modelling results with a number of other different modelling techniques including OLS, unit-cost analysis, and SFA. The resulting efficiency scores need not be mechanistically translated into revenue caps, but, could instead be subject to a degree of regulatory judgement. In GB, revenue caps are determined by a detailed analysis of the extent to which companies' business plans are 'well-justified'. However, this approach would be intensive in terms of regulatory input, which would be potentially infeasible in a system with a large number of DSOs.

- **By adopting a light-touch approach, as the Netherlands, NVE could** improve its model transparency, and reduce its model complexity. However, there is the risk that the large number of differences between the 150 companies would be missed. This could result in the need to be more generous (potentially in an arbitrary manner) elsewhere in the settlement. We therefore do not consider this approach to be applicable to Norway.

- **By using two different modelling techniques, as in Germany and Austria,** NVE could test the sensitivity of its benchmarking results to its choice of inputs, outputs and functional form. However, there is a risk that sensitivities introduce ambiguity in the results and increase the scope for regulatory lobbying. Multiple models may also increase the level of complexity involved in the benchmarking exercise. Furthermore, the impact of this approach on incentives for efficiency and investment would depend on how these multiple model specifications are used to set the revenue caps.

- A 'best-of' approach, as in Germany, would create the strongest incentives for investments, as the revenue cap for the companies is based on the model which would give them the highest allowed revenues. However, incentives for efficiency would be low.
- A weighted average approach would provide more of a balance between efficiency and investment incentives, when compared to the 'best-of' approach. However, there may be a great deal of ambiguity in instances when the results from the two models are drastically different, which would create scope for regulatory lobbying to determine how much weight should be attached to each of the models.
- As an alternative, the regulator could also apply a filter to mechanistically use the benchmarking results only when it would be appropriate to do so. For example, the regulator could use an average of the results from the two models, except in cases where they are drastically different (when the difference between the efficiency scores is greater than 20%, for example), when greater regulatory scrutiny could be applied. A benefit of this approach is that strikes a good balance between the use of mechanistic rules (when there is confidence in the results) and the application of regulatory judgement (when the results are more ambiguous).

- **By using the outlier detection techniques, as in Germany,** including 'super-efficiencies' and peer analysis, NVE could account for errors in the DEA benchmarking. This is an easy win, as it does not require a material increase in regulatory burden. While super-efficiency analysis is already being conducted in Norway, NVE could also test the use of peer analysis.

We consider the method of translating the benchmarking results to revenue caps in GB to be relatively intensive in terms of regulatory input, and the light-touch approach in the Netherlands to be ineffective in controlling for all the differences between the networks in Norway. While these approaches have their advantages, they are potentially infeasible in a system with a large number of DSOs. Of the feasible approaches, NVE could improve its benchmarking model by statistically testing for some of the outputs that it currently includes in its DEA model, and by a greater emphasis on outlier analysis. Furthermore, we recommend the use of a complementary benchmarking technique, such as SFA, as is done in Germany and Austria, as a useful cross-check for NVE's DEA results. Finally, to translate these benchmarking scores into revenue caps, we would recommend examining the option of a filter to use mechanistically an average of the benchmarking results, only when appropriate (when the difference between the two models is less than 20%, for example).

8.2.4 Issue 4: weak regional grid model

There are drawbacks associated with NVE's regional grid model in relation to large cost variations from one year to the next. While this is related to our discussion of issue 1 above, we understand from our dialogue with Energy Norway that concerns with the large lumpy investments affect the benchmarking of regional grid to a greater extent than the distribution grid.

Furthermore, like Statnett, some of the regional network companies also own transmission lines. However, while Statnett has high incentives to invest under rate of return regulation, the regional networks are regulated using a yardstick model, which provides weak investment incentives. Meeting Statnett's requirements for investing in new transmission lines is a challenge for the regional network companies under the current regional grid model.

In this context, we assess the credibility of regulating the regional grid under a framework of yardstick regulation using DEA benchmarking, and discuss some alternatives.

From the case studies, we have considered a number of options for change.

- **Approach A: Austria – Partial costs-pass through of capital costs:** E-Control has separate ways of regulating operating and capital costs. While Opex is still incentivised based on a benchmarking analysis, capital costs are subject to a partial cost-pass through for investments by the so called "investment factor". As a consequence, while the regulation of Opex is still incentive-based, the regulation of capital costs includes substantial cost-plus elements. Under this approach, the impact of lumpy investments on companies' revenues should be dampened.
- **Approach B: GB and Germany – reduced reliance on benchmarking:** At the transmission/distribution level in GB, and the transmission level in Germany, the use of benchmarking to determine allowed revenue is reduced. In GB, there is little reliance on benchmarking other than at unit cost level, and Germany introduced several pass through mechanisms (e.g. investment budgets, hardship clause). On these lines, one option to regulate the regional grids would be rely less heavily on the benchmarking analysis, and give more discretionary power to the regulator when setting the revenues.
- **Approach C: Netherlands – adjusting the regional grid model:** One final option would be to retain the framework of yardstick regulation, and to improve investment incentives for the companies to the extent possible by adjusting NVE's current model as it stands.

Below, we discuss each of these options for change, alongside the five assessment criteria that we identified earlier. We also analyse the key tradeoffs that may be associated with adopting each option.

Approach A: "Partial pass-through of capital costs": assessment

One approach to mitigate the issues associated of the lumpiness of investment in the regional grid is to introduce separate regulation for Opex and capital costs:

- **Opex Yardstick** – Operating costs could still be regulated using the yardstick, based on adjusted benchmarking analysis focussing on maintenance and operational costs;
- **Capital cost-plus regulation** – Capital costs, on the other hand, could be treated as a cost-pass through item.

Below, we analyse this option for change against our five assessment criteria. We also identify the key trade-off associated with implementing this change:

- *Incentive for cost efficiency* – this approach would decrease incentives for cost efficiency for two reasons. First, there is no incentive to reduce capital costs, as they are treated as a costs-pass through item. Second, it would reduce the incentive to reduce opex, and create incentive for companies to declare opex as investments, as this would improve their position in the opex benchmarking analyses, and they have capital costs directly passed through.
- *Incentive for investments* – Investment incentives under this approach are high, as capital costs are directly passed through. However, the different treatment of opex and investments may lead to suboptimal decisions on capital intensity from a total cost perspective. Companies may undertake replacement investments too early, despite maintenance expenditures being sufficient to sustain the quality of service of the asset. Therefore, this approach would incentivise companies to adopt capital intensive solutions even when these may not be necessary.
- *Applicability to Norway* – the split of regulation for opex and capital costs requires a "philosophical" change in the regulatory framework in Norway away from incentive-based regulation being in place since 1996 to the "old style" cost-plus regulation system used before.
- *Practicability* – the approach would require a significant degree of change in the way the regulatory framework operated in Norway. First, an Opex benchmarking model would be. Second, transparent rules for activation of investments would be needed. Finally, some investment audit mechanism would be necessary to avoid an outcome of "too much and too expensive" investment. This will substantially increase the regulatory scrutiny of NVE and we expect the manpower at the regulator.

Implications for Norway

- *Main trade-off* – this approach removes the adverse effect on revenues from lumpy investments, and creates strong investment incentives. However, it has two drawbacks. First, it may create an incentive to over-capitalise, and trade-off opex intensive solutions for capital intensive ones. Second, it would require a significantly higher degree of regulatory scrutiny and involvement in management decisions.

Approach B: "Reduced reliance on benchmarking": assessment

The current Norwegian approach to benchmarking and setting annual revenues leads to a volatile revenue stream over time for the regional grid, due to the lumpy nature of its investments. One approach to overcome this issue for the regional grids would be rely less heavily on the benchmarking analysis, and give more discretionary power to the regulator when setting the revenues. This approach is commonly used by regulators at the transmission level.

At the transmission/distribution level in GB, and the transmission level in Germany, the use of benchmarking to determine allowed revenue is reduced. In GB, there is little reliance on benchmarking other than at unit cost level, and Germany introduced several pass through mechanisms (e.g. investment budgets, hardship clause).

In the Netherlands, there was a political decision that TenneT should take over all the 110kV assets from the distributions companies. One of the arguments in favour of this restructuring of the network industry was that the 110kV network is regional in its characteristic and that TenneT is better able to coordinate the optimisation of the 110kv grid than the distribution companies. Given these similarities between the regional and transmission grids, NVE could consider reducing its reliance on benchmarking to regulate its regional grid, as is common in the regulation of transmission assets.

Below, we analyse this option for change against our five assessment criteria. We also identify the key trade-off associated with implementing this change:

- *Incentive for cost efficiency* – this approach should decrease the incentive for cost efficiency because it opens room for companies to lobby for their best results. This could create the likelihood that companies may gain much more from allocating management resources to discussions with the regulator than to internal cost optimisation processes.

- *Incentive for investments* – incentive for investments would depend on the attitude of the regulator, while are more likely to be positive than negative. However, an increase in regulatory judgement may increase the overall uncertainty of the regulatory regime and make it less transparent for investors. This may discourage some investments.

- *Applicability to Norway* – this approach would require a fundamental change in the regulatory framework in Norway, moving away from a transparent mechanistic application of the results from the benchmarking analysis, towards a system of in which more regulatory judgment would be used by NVE.
- *Practicability* – given that this approach is centred around the use of a greater degree of regulatory judgement, and reduced reliance on benchmarking, it would require a significant degree of increase in regulatory scrutiny on behalf of NVE.
- *Main trade-off* – while investment incentives under this approach would depend on the attitude of the regulator, we wold expect these to be high. However, this may come at the expense of increased lobbying and rent seeking behaviour on the part of the companies, and reduced incentive for overall cost efficiency. Moreover, given that this approach is centred on the use of a greater degree of regulatory judgement, it would require a significant degree of increase in regulatory scrutiny on behalf of NVE.

Approach C: "Adjust regional grid benchmarking model": assessment

Approaches A and B would both require a shift from the use of incentive regulation, to greater cost pass-through type regulation. A third option is to retain the framework of yardstick regulation as is currently adopted by NVE, and improve investment incentives to the extent possible within this framework. However, finishing the right benchmarking may be a challenge.

One of the drawbacks associated the current regional grid benchmarking model is its lack of investment incentives. We distinguish between two types of investments:

- replacement investments; and
- extension investments.

While extension investment incentives are already low, due to the bias associated with the age of the network and the lumpy nature of these investments, there is an additional disincentive for replacement expenditure. This is in relation to the lack of a corresponding output in the DEA model, for replacement costs incurred by the companies.

One option to overcome this issue would be to include some appropriate output measures in the DEA benchmarking model. Under this approach, an increase in replacement expenditure would be accompanied by an increase in outputs, which would increase incentives to incur these costs. A measure for quality of supply would be one option. However, this may not be an ideal output measure for replacements, as there may be a time-lag between the time in which the replacement investment is made, and the time when an increase in quality of supply is observed.

Below, we analyse this option for change against our five assessment criteria. We also identify the key trade-off associated with implementing this change:

- *Incentive for cost efficiency* – this approach would have a positive effect on the cost efficiency, as replacement expenses would be accompanied by a corresponding output in the DEA model. This would be a more accurate assessment of the performance of the companies. However, it would be a challenging to find an appropriate output measure for this purpose.
- *Incentive for investments* – this approach would provide strong incentives for replacement expenditure, as companies would no longer be penalised for not having a corresponding output associated with these expenses.
- *Applicability to Norway* – this approach requires no fundamental change in the regulatory framework in Norway.
- *Practicability* – while it would be a challenging to find an appropriate output measure to correspond an increase in replacement expenditure, no further regulatory scrutiny would be necessary.
- *Main trade-off* – this approach would have a positive effect on both cost efficiency and investment incentives, as replacement expenses would be accompanied by a corresponding output in the DEA model. However, the main challenge associated with this approach would be to find an appropriate output measure that corresponds with the replacement expenditure incurred by the companies.

Summary and key recommendations

There are drawbacks associated with NVE's regional grid model in relation to large cost variations from one year to the next. While this is related to our discussion of issue 1 above, we understand from our dialogue with Energy Norway that concerns with the large lumpy investments affect the benchmarking of regional grid to a greater extent than the distribution grid.

Furthermore, like Statnett, some of the regional network companies also own transmission lines. However, while Statnett has high incentives to invest under rate of return regulation, the regional networks are regulated using a yardstick model, which provides weak investment incentives. Meeting Statnett's requirements for investing in new transmission lines is a challenge for the regional network companies under the current regional grid model.

In this context, we assess the credibility of regulating the regional grid under a framework of yardstick regulation using DEA benchmarking, and discuss some alternatives.

From the case studies, we have considered a number of options for change.

- **By using a partial costs-pass through of capital costs, as in Austria,** NVE could remove the adverse effect on revenues from lumpy investments, and create strong investment incentives. However, this approach has two drawbacks. First, it may create an incentive to over-capitalise, and trade-off opex intensive solutions for capital intensive ones. Second, it would require a significantly higher degree of regulatory scrutiny and involvement in management decisions.

- **By reducing its reliance on benchmarking, and using more discretionary power in setting the revenues,** NVE could shift to an approach that is commonly used in regulation at the transmission/distribution level in GB, and the transmission level in Germany. While investment incentives under this approach would depend on the attitude of the regulator, we would expect these to be high. However, this may come at the expense of increased lobbying and rent seeking behaviour on the part of the companies, and reduced incentives for overall cost efficiency. Moreover, given that this approach is centred on the use of a greater degree of regulatory judgement, it would require a significant degree of increase in regulatory scrutiny on behalf of NVE.

- **By retaining the framework of yardstick regulation,** NVE could still attempt to improve incentives for investment. For example, incentives for replacement expenditure in NVE's model are currently particularly low due to the lack of a corresponding output in the DEA model, for replacement costs incurred by the companies. One option to overcome this issue would be to include an appropriate output measures in the DEA benchmarking model. A measure of quality of supply would be one option. Under this approach, an increase in replacement expenditure would be accompanied by an increase in outputs, which would increase incentives to incur these costs. In theory, this approach would improve investment incentives. However, it would be challenging to find an appropriate output measure that corresponds with the replacement expenditure incurred by the companies.

As discussed above, there are strong trade-offs associated with each of these options for change. While yardstick regulation provides incentives for efficiency, it may not be effective to incentivising sufficient investments for the regional grid due to the bias associated with the lumpy nature of capital expenditure in these assets. While an output measure for replacement expenditure could be designed for NVE's current DEA model, finding an appropriate measure may be challenging in practice. On the other hand, NVE could explore the use of some degree of cost pass-through for capital costs. This would create strong investment incentives, and may encourage to companies to over-capitalise, and would require a significantly higher degree of regulatory scrutiny and involvement in management decisions. NVE's choice of approach would need to depend on the extent to which it prioritises investment incentives over efficiency incentives, as there is a clear trade-off between the two in this issue.

8.2.5 Issue 5: innovation incentives

The European energy system is undergoing fundamental changes due to the EU 20/20/20 targets. This puts new challenges on electricity distribution grids to:

- integrate renewable generation at low voltage levels;
- cope with non-predictable or difficult to predict volatile generation from certain renewable technologies, e.g. wind and PV; and
- deal with temporal drift apart of generation and demand.

Hence, there is a greater need for:

- rewarding and incentivising capital expenditure for smart grids; and
- incentivising innovation and R&D funding.

From the case studies, we have identified two options incentivise investments and innovation.

- **Approach A: GB – greater regulatory certainty & explicit funding:** The new RIIO framework is designed to provide strong incentives for innovation. The price-control period will be extended from 5 to 8 years, improving regulatory certainty for investors. Furthermore, several elements of the price control have been designed to improve incentives for innovation, including a greater output focus, and emphasis on the use of well-justified business plans. Finally, there exists a separate innovation stimulus package for electricity and gas networks aimed at any investment that is focused on sustainable development.

- **Approach B: Austria and Italy[12] – mark-up on investments:** A mark-up on WACC can be introduced to stimulate further investment and innovation. This is done, for example, in Austria and Italy.
  - In the 2nd regulatory period in Austria, E-Control introduced an "investment factor", or a general mark-up on WACC of 1.05% on

12 Italy was not included in the detailed case studies, however, we think that the approach used for incentivising investments may be of interest for Norway, as well.

cumulative gross investments. As this is a 'general' mark-up, as E-Control does not distinguish between general and smart investments.

- Italy has a system of cost-plus regulation for capital costs, with mark-up on WACC for certain types of investments made by electricity distribution companies post December 31st, 2007, including:
  - A Mark-up of 2% over 8 years for transformer stations reducing network losses
  - A Mark-up of 2% over 12 years for investments in network automatisation

  In 2011, a new system was introduced in Italy to distinguish between different types of investments, ranking them using transparent criteria to evaluate their importance.

Below, we discuss these two options for change, alongside the five assessment criteria that we previously identified. We also analyse the key tradeoffs that may be associated with adopting each option.

Approach A: "WACC mark-up": assessment

The sustainability agenda creates a strong need for investment and innovation incentives, given the requirements for large-scale network investment in the future. This need for investment and innovation incentives is further intensified in Norway, by the possibility that it's regulatory WACC has historically been too low, when compared to the other countries in our case studies. In Table 7, we identify three parameters for setting the WACC, all of which are relatively low when compared to the countries included in our case studies.

- **Market risk premium** – the market risk premium for Norway is at the lower bound of the range of 4% to 6%, indicating that there is some upside.
- **Asset beta** –the asset beta for Norway is relatively low when compared to the Netherlands.
- **Debt spread** – the debt spread for Norway is below the range of 0.8% to 1.9%, indicating that there is some upside.

Table 7. Comparison of WACC parameters for electricity distribution companies

	Norway[13]	Netherlands (2011-13)	Germany (2009-13)	Austria (2010-13)	UK (2010-15)
Market risk premium	**4%**	4% - 6%	4.55%	5%	5.25%
Asset beta	**0.35**	0.39-0.49	0.35	0.325	0.39
Debt spread	**0.75%**	1.1% -1.9%	na	0.8%	1.25%
Gearing	60%	50% - 60%	na	60%	62.5% - 65%

Source: NVE (2011), Frontier

These comparisons suggest that there may be some upside in the WACC in Norway for the coming regulatory period, when relative to the NVE (2011) figures.

This additional upside could come from a mark-up on WACC for certain types of investments, as is done in Austria and Italy, and could be used as an instrument to incentivise innovation and investments in Norway:

Below, we analyse this option for change against our five assessment criteria. We also identify the key trade-off associated with implementing this change:

- *Incentive for cost efficiency* – we would expect there to be no adverse effect on cost efficiency from a WACC mark-up, under a system yardstick regulation using benchmarking analysis. However, under a regime of cost-plus regulation for capital costs, a mark-up on the WACC would encourage companies to over-invest, as these costs would be directly passed through.

- *Incentive for investments/innovation* – this approach would provide a strong incentive for investments. Furthermore, by distinguishing the mark-up by investment type (as is done in Italy), rather than providing a single general mark-up on all investments (as is done in Austria), one can also stimulate innovation in particular. However, under a regime of cost-plus regulation for capital costs, this approach may lead to substantial overinvestment.

13 NVE, Vil reguleringen gi tilstrekkelig avkastning?, Energidagene2011.

- *Applicability to Norway* – this approach requires no fundamental change in the regulatory framework in Norway and could be considered by NVE.
- *Practicability* – This approach would not require a significant increase in the level of regulatory scrutiny.

Main trade-off – this approach is a direct and simple way of incentivising investment and innovation. However, it is a potentially "blunt instrument", and can be overgenerous, encouraging companies to over-invest, particularly under a regime of cost-plus regulation. Nevertheless, such an approach may be applied to investments, such as smart grids, where there are financial risks to the investor that may not be adequately reflected in the underlying WACC used for standard regulated investments.

Approach B: "greater regulatory certainty and innovation funding": assessment

Under the RIIO model, Ofgem will provide incentives for innovation in two ways.

- First, the longer-term, outputs-led, incentive-based, ex ante price control is designed to provide incentives to innovate, by giving companies a commitment around the potential rewards that they could earn from successful innovations, and by committing not to penalise them for unsuccessful innovations; and
- Second, Ofgem will provide partial financing for innovations related to delivery of a sustainable energy sector, through an electricity networks innovation stimulus and a gas networks innovation stimulus package.

This innovation stimulus fund may be administered by the regulator and/or other stakeholders. Companies can apply to the fund to get innovative projects co-financed by the fund. Transparent rules are necessary, which determine:

- which project can apply for co-financing;
- when and how much money the project gets; and
- what happens if the project is not undertaken by the company.

Below, we analyse this option for change against our five assessment criteria. We also identify the key trade-off associated with implementing this change:

- *Incentive for cost efficiency* – this approach would have a positive effect on cost efficiency, as companies would be encouraged to adopt solutions that are efficient in the longer-term if, for example, costs in the current price control lead to greater output-delivery in the future.

- *Incentive for investments/innovation* – while the longer-term, outputs-led, incentive-based price control is designed to stimulate investments in general, the innovation stimulus package provides partial financing for innovations related to delivery of a sustainable energy, in particular. However, regulatory judgment is necessary to decide the "right" investments that should be included in the package, which creates the scope for lobbying by the companies.

- *Applicability to Norway* – a stimulus fund can be considered by the regulator in Norway. However, due to the large numbers of companies in operation, designing the details of such a stimulus fund may be more complex. Furthermore, adopting other elements of the price control in GB, such as the use of well-justified business plans, would require significant regulatory changes.

- *Practicability* – Adopting an innovation stimulus package would not require a significant increase in regulatory scrutiny. However, a transparent procedure would need to be designed to allocate the money from such a stimulus fund. On the other hand, adopting a longer-term, outputs-led price control centred on well-justified would require a significant degree of regulatory scrutiny, which may not be practicable given the large number of distribution networks in Norway.

- *Main trade-off* – an innovation stimulus fund would be an effective instrument for providing innovation incentives. However, designing and operating such a fund may be quite complex in the Norwegian landscape of more than hundred network companies. On the other hand, while other elements of the price control in GB, such as the use of well-justified business plans, would also stimulate investments, they may not be applicable to Norway given that they require a significant amount of regulatory scrutiny.

Summary and key recommendations

Driven primarily by the green agenda, there is a greater need for rewarding and incentivising capital expenditure for smart grids, and incentivising innovation and R&D funding in the future in Norway. Furthermore, we understand from our discussions with Energy Norway that there are concerns that NVE's regulatory WACC may have historically been too low to incentivise sufficient investments. We compare the parameters used to set the WACC in Norway with the countries in our case studies, which suggest that there may need to be some upside in NVE's WACC going forward.

In this context, we explore two ways of stimulating further investment and innovation in Norway.

- **By creating an explicit stimulus package, as in GB**, NVE, could effectively incentivise any investment that is focused on sustainable development. However, designing and operating such a fund may be quite complex in the Norwegian landscape of more than hundred network companies. On the other hand, while other elements of the price control in GB, such as the use of well-justified business plans, would also stimulate investments, they may not be applicable to Norway given that they require a significant amount of regulatory scrutiny.

- **By providing a mark-up on WACC for investments incurred by the DSOs, as in Austria and Italy**, NVE could effectively incentivise any type of investment. A benefit of this approach is that it is direct and simple way of incentivising investment and innovation. However, it is a potentially "blunt instrument", and can be overgenerous, encouraging companies to over-invest, particularly under a regime of cost-plus regulation.

We recommend that NVE explores the use of an innovation stimulus package in Norway. As noted, while there are drawbacks associated with the use of a WACC mark-up, it can be particularly effective if targeted at certain types of investments (investments in smart grids, for example), which the regulator may consider to be of high priority.

Annexe 1: Proposed changes to NVE's approach

Revenue caps in NVE's current model are estimated in nine stages. NVE is considering some changes to the first two stages of its model. In this annexe, we summarise NVE's current approach, outline the two options for change proposed by NVE, and discuss the pros and cons of each.

The efficiency score for each distribution network is currently calculated in the first stage for NVE's model, through DEA benchmarking. The model is estimated using total costs as an input, and eight outputs, two relating to network structure (high voltage lines and network stations), three relating to the demand for electricity (subscriptions not including vacation homes, subscriptions for vacation homes, and delivered energy), and three measuring topographical factors (forest, snow, and wind/coast).

The DEA efficiency scores from stage one are then adjusted for three environmental factors (specifically, island connections, transmission interfaces, and distributed generation) in the second stage. This is done by regressing the efficiency scores from stage one on the three environmental factors in stage two. The resulting coefficients are then used to calculate an environmental factor correction (EFC) for each of the companies. The EFC determines how much of a disadvantage (in units of efficiency score) each grid company suffers given the amount of Islands, Interfaces and DG on its network. This adjustment makes the efficiency scores from stage one more comparable, or so that they correspond to a more common level of environment.

A drawback of using DEA as a benchmarking technique is that the number of frontier firms tends to increase (and efficiencies are therefore overestimated) as variables are added to the model. There is, therefore, a trade-off between being able to capture all the drivers of performance in the DEA model and being able to distinguish between the efficiency performance of firms.

To overcome this drawback, NVE has proposed to include some of these drivers of performance in the stage-two regression analysis, instead of the stage-one DEA analysis. This is likely to ease the overestimation of efficiency scores associated with NVE's current approach of including a large number of explanatory factors in its stage-one DEA model. For example, NVE is testing the impact on moving the topographical factors (including forest and wind/coast, for example) from the DEA analysis in the first stage, to the second stage regression analysis.

To account for the increased number of output variables in its stage two regressions, NVE:

- first tests for the statistical significance of each of the explanatory variables by individually regressing the variable against the DEA efficiency scores from stage-one;
- then identifies those variables that are statistically significant; and
- finally, tests for the multicolleanearity between these statistically significant variables.

We understand that NVE is considering two broad types of approaches to account for this increased number of output variables in its stage two regressions.

- First is the use of an aggregated output variable.
- Second is the use of factor analysis, including common factor analysis (CFA) and principal component analysis (PCA).

Below, we outline these two approaches in more detail, and consider the benefits and disadvantages of each.

Option 1: using an aggregated output variable

Under this approach, an aggregated output variable is created, which is a weighted average of the set of statistically significant output variables identified by NVE. In its regional grid model, for example, NVE identifies two types of variables to be statistically significant. These include a number of variables describing forests, and a single variable describing the slope (or "hilliness") of the region. As slope is identified to be highly correlated with some of the forest variables, the final aggregated output variable is selected to be a sum of the individual forest variables that are statistically significant.

A similar approach was adopted by Ofgem in GB in its third and fourth distribution price control reviews (1999 – 2009). Ofgem derived a composite measure of output (number of customers 50%, units distributed 25%, and network length 25%), in its opex benchmarking for distribution networks. A similar method was used in its opex benchmarking in the most recent price control, although a more sophisticated approach was used to derive the weights that should be associated with each of the output variables.

Option 2: using factor analysis

Factor analysis is an alternative approach that can be used to overcome the issues of multicollinearity and loss of degrees of freedom associated with the use of multivariate regressions. Factor analysis describes the variability within the large number of statistically significant variables identified by NVE, in terms of a fewer unobserved variables called 'factors' or 'components'. The aim of this approach is to capture the variation within a large number of variables, and analyse groups of correlated variables, into one or more common domains. NVE is testing the use of two types of factor analysis.

- **Principal component analysis (PCA)** creates a linear combination of variables, such that the maximum variance is extracted from the individual variables. In doing this, it reduces the number of explanatory variables in the model to a smaller number of 'principal components' which account for most of the variation within the full set of explanatory variables.

- **Common factor analysis (CFA)** similarly reduces the full set of explanatory variables in the model into a smaller number of 'factors', but under a different set of assumptions to PCA about the correlation between the explanatory variables.

We understand from our discussion with NVE that both PCA and CFA provide similar results for a given set of data.

Pros and cons of NVE's proposed options for change

As outlined above, NVE is considering two approaches to remedy the potential problems with the large number of explanatory variables it is proposing to use in its second stage regressions. Both the approaches explored by NVE are designed to summarise a large number of observed explanatory variables into a smaller number of derived variables. However, there are pros and cons associated with the use of both these approaches. These are outlined below.

The first approach considered by NVE is the use of an aggregated output variable. A benefit of this approach is that it overcomes the issues of multicollinearity and loss of degrees of freedom associated with the use of multivariate regressions. On the other hand, the main risk of this approach is the loss of information associated with the creation of composite scores. Furthermore, there is a risk of attaching the wrong weights to the explanatory variables in the model, which would need to be considered carefully.

The second approach considered by NVE is the use of factor analysis. A benefit of this approach (as with the use of an aggregated output variable) is that it overcomes the issues of multicollinearity and loss of degrees of freedom associated with the use of multivariate regressions. However, the main advantage of factor analysis over the use of an aggregated output variable is that it retains, by construction, the maximum amount of information on the variation within the variables that are aggregated. It is worth noting, however, that the main drawback associated with the use of factor analysis is its lack of regulatory precedent, as it has not been tested in the benchmarking of distribution networks in actual practice.

Annexe 1: Proposed changes to NVE's approach

Annexe 2: Issues with partial cost pass-through

In Chapter 8, we discussed the drawbacks of regulating the regional grid using a framework of yardstick regulation with DEA benchmarking. One of the main concerns with this approach is that it causes the benchmarking analysis to be sensitive to large cost variations from one year to another because of "lumpy" capital and replacement expenditure in the regional grid. To mitigate this issue, one of the alternatives we considered was use of some degree of cost pass-through for capital costs (as in Austria). We suggested that this would create stronger investment incentives, but may encourage to companies to over-capitalise. In this annex we:

- discuss the rational for the pass-through of capex;
- examine the issues associated with capex cost pass-through regulation in more detail; and
- consider an alternative to the traditional pass-through model than can be applied to in the Norwegian context.

Rationale for the pass-through of capex

In this section, we discuss the rationale for the pass-through of capex. The inherent differences in the nature of opex and capex may create difficulties in benchmarking these two costs together. Furthermore, the inherent 'lumpiness' in the nature of capex creates challenges in benchmarking these costs across companies even on their own (separate from opex) on a like-for-like basis. To overcome these drawbacks associated with benchmarking capex, and incentivise sufficient long-term network investment going forward, some regulators (such as E-control in Austria) have used a partial pass-through of capital costs in their regulatory systems. These issues are discussed in the sub-sections below.

Inherent differences between opex and capex

There is a fundamental difference between opex and capex in relation to the nature in which these costs are incurred, and the way in which they are remunerated over time.

- Opex includes costs that relate to the day-to-day operation of the business. It is remunerated in the year in which the cost is incurred.

- Capex includes costs that relate to longer-term infrastructure investments. Capex incurred in the current period relates, in part, to current needs and, in part, to future needs. It is therefore not entirely recovered in the year of incurrence, but over the lifetime of the asset. Only a proportion of capex is remunerated in the year in which it is incurred (through depreciation, and a cost of capital for the addition to the RAV).

This fundamental distinction in the nature of opex and capex makes it difficult for these costs to be benchmarked together.

Difficulties even in benchmarking capex on its own

As the profile of operating costs is more comparable across companies, it is easier to benchmark these costs on a like-for-like basis. This has motivated regulators to historically adopt yardstick regulation with some form of benchmarking analysis of operating costs.

On the other hand, as capex is inherently 'lumpy' by nature, the benchmarking of capital costs can be very sensitive to cost variations from one year to another. This is particularly true for the nature of investment in the regional grid, which tend to be more 'lumpy' than investments in the distribution grid.

There are two broad types of approaches that can be used to average these capital costs over a long time to overcome the drawbacks associated with their inherent 'lumpiness'.

- **The total cost approach** benchmarks the sum of actual operating costs, and a measure of capital consumption (including a return in accordance with the regulatory cost of capital, and an allowance for depreciation). This is the approach currently adopted in Norway.

- **The total expenditure approach** benchmarks a sum of actual operating costs, and a long-term average of actual annual capex. This is the approach that has been proposed by Ofgem for the next price control in GB, but has not been tested in actual practice.

While both these approaches can be effective in "averaging" capex in some way, this averaging of costs creates problems of its own. As discussed in the previous sub-section, capex incurred in the current period relates, in part, to current needs and, in part, to future needs. The benefits of capex incurred in the current period, therefore, may only be observed in future periods. However, benchmarking models use cost drivers corresponding to a single period (the current period), to explain an average (over time) of capital costs. Therefore, capex would still be disincentivised under this approach, if the increase in capital costs doesn't correspond with an increase in output in the current period. This issue is particularly relevant for replacement investments incurred by companies, which are not associated with a respective increase in output (even though they may improve quality of supply in the longer-term).

Separate regulation for opex and capex

One option to overcome these drawbacks associated with the benchmarking of capex, and incentivise sufficient long-term network investment going forward, is to introduce separate regulation for opex and capex (as has historically been done in GB):

- **Opex yardstick** – Operating costs could still be regulated using the yardstick, based on adjusted benchmarking analysis focussing on maintenance and operational costs;
- **Capex cost-plus regulation** – Capital costs, on the other hand, could be treated as a cost-pass through item.

By overcoming the adverse effect on revenues from lumpy investments, this approach creates strong investment incentives. Furthermore, as discussed in chapter 8, Furthermore, some of the regional network companies, like Statnett, also own transmission lines. However, while Statnett has high incentives to invest under *de facto* rate of return regulation, the regional networks in Norway (that do not have this type of regulatory approach) have weaker investment incentives under the current yardstick model. It can be argued that capex cost pass-through may better incentivise regional grid companies to meet Statnett's requirements for investing in new transmission lines.

However, there are drawbacks associated with the direct pass-through of capital costs. These are discussed below.

Issues with pass-through of capex

Despite the inherent differences between opex and capex, there is a trade-off between these costs. An example of this tradeoff is between maintenance costs (opex) and replacement costs (capex). As a result of this trade-off, there are two main drawbacks associated with the use of partial cost pass-through for capex (while maintaining a yardstick model for opex).

- First, it may create perverse investment incentives, and 'boundary issues'.
- Second, it would significantly increase regulatory burden.

These issues are discussed below. However, it is worth nothing that it is to overcome these drawbacks that a number of European regulators, including NVE, have historically adopted a regulatory system based on total costs.

Perverse investment incentives and boundary issues

If the regulatory incentives for incurring opex and capex are the same, then in cases where there is a trade-off, companies would choose between these two types of costs by assessing the option that delivers the best long-term value for money. However, the risk of using yardstick regulation for operating costs, on the one hand, and a direct pass-through of capital costs, on the other, is that it may create an incentive to over-capitalise, and trade-off opex intensive solutions for capital intensive ones. In other words, the trade-offs between opex and capex may not be optimised under this approach, as networks would be incentivised to replace their assets too early, rather than incurring maintenance costs, for example. Furthermore, this approach may crease 'boundary issues' in the reporting of these costs, as regulated firms would benefit by classifying operating costs as capex, because this moves costs out of an area with stronger efficiency incentives and into an area with weaker efficiency incentives.

An example of imbalance in incentives in GB in DPCR4

Ofgem has recognised that there were imbalances between the incentives for different types of costs in its fourth distribution price control (DPCR4) from 2005-2010. These imbalances may have distorted the decisions that regulated firms needed to make between capex and opex solutions. As a result of the design of Ofgem's capitalisation policy in DPCR4, the regulated firms had to bear the full cost, or 100% of any overspend on opex, but only 29–40% of any overspend on capex. As a result, incentives were distorted towards adopting capex rather than opex solutions, rather than aiming at minimising total lifetime costs.[14]

This also created 'boundary issues' in the reporting of these costs, as regulated firms benefited if more direct operating costs (such as tree cutting, fault costs, or inspections and maintenance) were classified as network investment or indirect costs, because this moved costs out of an area with stronger incentives and into an area with weaker incentives.[15] To overcome this drawback, a significant amount of Ofgem's resources during DPCR4 and DPCR5 were spent on monitoring the boundary between various cost categories—eg, the distinction between fault costs and asset replacement or the treatment of site engineer costs. However, this tends to be a "second-best" solution.

14 Ofgem (2009), 'Electricity Distribution Price Control Review Initial Proposals: Incentives and Obligations', August.

15 Ofgem (2009), 'Electricity Distribution Price Control Review: Methodology and Initial Results Paper', May 8th, paras 9.1–9.2; Ofgem (2009), 'Electricity Distribution Price Control Review: Final Proposals – Incentives and Obligations', December 7th, Chapter 21.

In DPCR5, Ofgem aimed to equalised incentives by capitalising a fixed percentage of costs across all network investment, network operating costs and closely associated indirect costs in the same way into the RAV.[16] A similar approach is proposed for the RIIO model.

Furthermore, in its RIIO model, Ofgem proposes to use total cost benchmarking to consider the efficient level of total costs of delivery in the long term, and overcome the issues associated with the trade-off between opex and capex.[17]

Increase in regulatory burden

An approach of partial pass-through of capital costs would require a significant degree of change in the way the regulatory framework currently operates in Norway.

- First, a separate Opex benchmarking model would need to be created for the regional grid (to replace the totex model that has historically been used).
- Second, transparent rules for activation of investments would be needed.
- Finally, some investment audit mechanism would be necessary to avoid an outcome of excessive and expensive investment.

This will substantially increase the regulatory scrutiny of NVE and we expect the manpower at the regulator.

To overcome the drawbacks of distorted incentives and increase in regulatory burden, we consider an alternative to the traditional pass-through model that can be applied in the Norwegian context. This is discussed below.

An alternative to the traditional cost pass-through model

As discussed above, there are a number of drawbacks associated with the use of capex pass-through, specifically relating to the tradeoff between opex and capex, and the increase in regulatory burden associated with this approach. We consider an alternative type of pass-through model, wherein, by reducing the weight attached to norm costs, and thereby increasing the pass-through of historic costs, the regulator could incentivise investments in Norway. This was an approach discussed in our workshop with NVE.

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16 Ofgem (2009), 'Electricity Distribution Price Control Review: Methodology and Initial Results Paper', May 8th, para 9.11.

17 Ofgem (2010), 'Handbook for implementing the RIIO model', October, para 8.5.

Allowed revenues in the under the current yardstick model in Norway are determined by a combination of:

- norm costs, or the efficient level of costs determined by the benchmarking analysis (which may be distorted by lumpy investments); and

- actual historic costs, or the actual outturn costs of the companies in t-2.

The final revenue cap for each company is a weighted average of its efficient level of costs, as determined by NVE, and its actual historic costs. In the current price control, the multiplier is set to 0.6. In other words, only 60% of the revenue cap is determined by the cost norm, or the efficient costs of the companies. The remaining 40% of the revenue cap is based on the company's actual historic costs. Therefore, NVE's model, as it currently stands, already has a pass-through element. This is to account for modelling errors and other differences between the grid companies that the model does not account for (associated, in part, with the 'lumpiness' of investments). A simple way to reduce the impact of these modelling errors, while increasing the incentives for investments, is to reduce the weight on norm costs, and increase the weight on actual costs (therefore increasing the size of the pass-through element of the model).

A benefit of this approach is that it can easily be applied in the Norwegian context, and would therefore require no increase in regulatory burden. However, as with all the regulatory approaches we discuss in chapter 8, there are trade-offs associated with the use of this type of pass-through. Reducing the weight on norm costs would increase the pass-through of both, opex and capex. While it can be argued that increasing the pass-through of capex would increase the investment incentives for companies, there is no corresponding benefit associated with increasing the pass-through of opex. In fact, this increase in pass-through of opex would reduce the incentives for the companies to be efficient. Therefore, this approach can be regarded as a "blunt instrument" to incentivise investments, as it would reduce the efficiency incentives for firms, and reduce the reliance of the regulatory regime on the benchmarking analysis conducted by the regulator.

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