

International Benchmarking of Electricity Transmission System Operators

e³GRID PROJECT – FINAL REPORT

Per AGRELL
Peter BOGETOFT

2009-03-09

Disclaimer

This is the final report for the e3GRID project for benchmarking of transmission system operators by SUMICSID, van Dijk Management Consultants and Tractebel Engineering SA. The document draws on confidential data submitted by the commissioning authorities.

The report is submitted to a subgroup of the CEER Workstream-Incentive based Regulation and Efficiency Benchmarking (WS EFB) of the CEER Unbundling, Reporting and Benchmarking Task Force (URB TF) as a final deliverable of the project.

The findings, conclusions and recommendations in the report only represent the viewpoint of the authors based on the analyses made in the project and cannot be taken as economic advice on the performance, optimal regulation or feasible policy of any given operator.

e3GRID Final Results
Final report, public, version 1.2. Project no: 340
Release date: March 9, 2009

Sumicsid SPRL
Rue de la piété 11
B-1160 BRUSSELS, BELGIUM
www.sumicsid.com

Copyright © 2009 SUMICSID SPRL.

Version history

Version	Date	Status	Concerns
0.7	2008-12-01	Draft	Pre-release
1.0	2008-12-31	Release	NRA review as OPEN
1.1	2009-01-31	Final	Final after NRA review as OPEN
1.2	2009-03-09	Final	Final approved

Executive Summary

This report presents the general results of the European benchmarking of electricity transmission system operators for the Council of European Energy Regulators (CEER) Workstream on Incentive regulation and efficiency benchmarking, made possible thanks to the active participation of 19 national regulatory authorities (NRAs) from Austria, Cyprus, Czech Republic, Denmark, Finland, Germany, Hungary, Iceland, Italy, Lithuania, Luxemburg, the Netherlands, Norway, Poland, Portugal, Slovenia, Spain, Sweden and the United Kingdom and 22 transmission system operators (TSOs), i.e. Verbund APG, Cyprus TSO, CEPS, Energinet.dk, Fingrid, Eon, EnBW, RWE, Vattenfall, Landsnet, Terna, Lietuvos Energija, CEGEDEL NET, TenneT, Statnett, PSE, REN, REE, Svenska Kraftnät, National Grid Electricity, SHETL and SPTL. The project (e3GRID) has been conducted intensively during the last eleven months of 2008, and this final reporting has been preceded by monthly meetings and two intermediate reports. In addition to the open general results, a confidential report is issued for a subset of NRAs agreeing mutually to disclose results (this subset is composed of the NRAs from CY, CZ, DE (2 TSO), DK, ES, FI, IS, LU, NL, NO, PL, PT, SE and UK, 3 TSO). All project participants have also received detailed individual confidential summaries of the data used, intermediate steps in the calculations and the individual final results.

The efficiency analysis for the TSOs is based on a combination of system science, engineering and econometrics. The overall objective of the project has been to deliver static and dynamic cost efficiency estimates that are robust and comprehensible and can be used in a variety of regulatory applications, from informing a comprehensive performance assessment to parameters in structured periodic rate reviews, e.g. setting of X-factors.

The X-factor is, according to internationally accepted best practice, divided into a general productivity improvement factor (X) and an individual efficiency catch-up factor (Xi). The first corresponds to the real cost changes for structurally comparable operations by efficient operators during the period 2003-2006. The latter is based on a cautious estimate of the incumbent inefficiency in the controllable cost for the reference year 2006 and a period of adjustment to efficient operations.

The analysis is based on submitted data from the operators, including detailed cost and asset data, data for physical outputs and staffing, data for the physical, economic and technical context of the operators, statements of operator specific costs, quality indicators and data related to the use of infrastructure for transport and regional transmission. The data have been consolidated by comparing them with annual public or regulated accounts, and out of scope items not subject to benchmarking have been audited by external auditors or NRAs. Submitted data from TSOs and NRAs have been validated in several rounds based on technical and economic validation processes and pre-run and post-run analyses by both consultants, NRAs and TSOs.

The methodological approach deployed is consistent with best regulatory practice and compliant with the CEER principles for the promotion of continuous infrastructure expansion. First, structural comparability in operating costs is achieved by a functional decomposition of the operators activities into a pre-established set of seven functions or roles: grid planning, grid construction, grid maintenance, system operations, market facilitation, administration and grid ownership. Costs within each function, reported by type of cost, are standardized with respect to currency, inflation adjustment and manpower compensation costs. Second, structural comparability in capital expenditure is accomplished by a complete restructuring of the capital base using a real annuity approach with standardized techno-economic lifetimes per asset type. Third, operational comparability is assured through an extensive statistical analysis of structural data in order to detect a valid set of cost drivers, besides the assets per se. Fourth, operator specific conditions and costs are reviewed through a structured and transparent submission process to minimize bias in the assessment.

The efficiency estimation techniques used depend on the character of the underlying functions in terms of homogeneity, cost causality and production space. The most extensive assessment is made using a non-parametric frontier model of the Data Envelopment Analysis (DEA) type under the assumption of non-decreasing returns to scale for a scope encompassing total expenditure for construction, maintenance, planning and administration (CMPA). The scale assumption, non-decreasing returns to scale, protects grids below the optimal size from comparing with most productive scale, while larger grids are compared to the entire set. The scope was determined from a model specification process based on average cost metrics tested for a large set of potentially relevant cost drivers.

The frontier model for CMPA consists of three output variables: a normalized grid metric, connection density and the capacity of connected power for renewable energy including hydro. The most important output for the chosen scope is the grid itself, alone explaining 83% of the variance in total expenditure among the operators. The normalized grid metric, based on a system of techno-economic weights, permits to take into account over 1200 different assets in eight groups, differentiated with respect to voltage, power, current, cross-section, complexity and other relevant dimensions. Second, both average cost, parametric and non-parametric analyses find that connection density is an important cost driver, since total expenditure is increasing in population and decreasing in area. Operators in densely populated areas incur higher costs in planning, constructing and maintaining grids due to direct (equipment choice, access conditions, monitoring) and indirect effects (higher urbanization drives meshed layouts with higher complexity, high load incidence drives costly maintenance schedules and requires shorter fault remedial times). Third, the generation park connected has a significant impact on the total expenditure for the service. A higher incidence of renewable and decentralized energy resources connected to the electricity grid causes significant costs not only in dimensioning for high intermittent power flows, such as wind, but also due to general reinforcements due to location far from load centers, more complex grid management due to unforeseen interactions from distribution networks operating in active and islanding modes, and evolving standards

for control and monitoring. Besides its statistical significance, the third variable for renewable power is also consistent with future network regulation under massive integration of decentralized and renewable energy resources that may prompt non-grid investments in control and load-side development that otherwise would be demoted in the analysis.

Through the application of advanced outlier detection techniques in regulatory use, the results for the frontier model show two distinct technologies: a low-cost transport design in use in certain low-density countries and a continental "standard" technology with relatively similar specifications. Within each technology, additional indicators for asset standards, e.g. tower incidence and design, are not significant. The static results after outlier detection indicate 87% total cost efficiency for the scope CMPA in the sample, a sensitivity analysis for various parameters and weights shows that the result is robust under a variety of hypotheses.

The dynamic results using the frontier model for a panel 2003-2006 developed in the project report on a yearly productivity growth for best-practice electricity transmission operators in the range of 2.2-2.5% in total expenditure for CMPA. These results can be compared to earlier European ECOM+ results based on unit cost development 2000-2003 of 1.3% per year, Norwegian regional transmission operators 2001-2004 showing 2.1% net real cost frontier shift per year, and American results for interstate transmission operators using FERC data 1994-2005 of 2.4% net cost-weighted frontier shift per year. The current e³GRID results further show positive productivity improvement rates for average and inefficient operators.

The static efficiency results are derived with several different approaches, including and excluding outliers, using frontier analysis or unit cost analysis, for total expenditure, operating cost analysis or capital expenditure. Detailed analysis for operators using the specific parameters used in national regulation has been done for some participating countries to adjust the analysis to the specific needs in incentive regulation.

The residual costs (S, X, F) are also analyzed. The heterogeneous but substantial costs for system operations (S) were found not to comply with the necessary homogeneity and controllability needed for inclusion in a frontier model. A proposal is presented to use a Fisher-approach, but the physical data collected during the last part of the project do not permit any general application of the method in this project. Market facilitation costs (X) are intrinsically related to the individual markets, both deregulated market places and national support programs for decentralized energy resources. Given the national regulatory and local price-volume dependency of the market facilitation costs, international benchmarking is not the most relevant regulatory tool in this respect. Finally, the grid financing costs (F) are analyzed from a corporate financial viewpoint, but with the important restriction not to extend the scope to other functions. The heterogeneity among transmission operators with respect to ownership and governance structure, legal and accounting basis, institutional history and asset control suggests that grid financing costs currently to a large extent are non-comparable among operators.

Compared to previous European ECOM+ studies, the present project has more than tripled the number of TSOs involved, relied on new and improved data definitions, covered a wider scope of activities and relaxed a series of assumptions about the underlying costs functions. Most notably, we have been able to relax the assumptions of constant return to scale and to include as cost drivers also contextual complexities like density and renewable energy. The results of ECOM+ and e3GRID are therefore not directly comparable.

In summary, the project has resulted in a set of static and dynamic efficiency measures that we believe are robust, cautious and forward-looking.

The robustness of the assessment is achieved through the following means:

1. *Application of average cost model analysis to find a useful model specification*
2. *Calibration of relative asset scaling weights to average European cost*
3. *Application of both stochastic and deterministic methods to the model analysis*
4. *Calculation and analysis of parametric models to validate choice of variables in order to avoid undue bias in model selection*
5. *Application of non-parametric outlier detection using the provisions of the German Incentive Regulation ordinance in order to limit influence of diverging technologies without resorting to ad hoc procedures*
6. *Extensive sensitivity analysis on interest rates, asset weights, life times, technical constants and salary correction indexes*
7. *Development, calculation and analysis of a proxy to correct for potentially incomparable opening balances for some operators*
8. *Administration and support costs are entirely included to avoid sensitivity with respect to overhead allocation rules etc.*

The cautiousness principle in the assessment of the improvement potential is expressed through the following allowances on benchmarked cost:

1. *Allowances. Costs that are structurally non-comparable and non-grid related, such as capital costs for land, buildings and non-grid installations are out of scope*
2. *No staff cost inefficiency. Manpower compensation costs are corrected using a transmission operator index that is based on actual observations from the national sample.*
3. *No extrapolation. Benchmarking with frontier methods is only performed for a limited scope for which the chosen model shows explanatory power also for average cost specifications*

4. *Asset promotion. Strict application of the CEER network expansion principle avoids all use of utilization metrics to penalize early or uncertain investments and to guarantee investment incentives*

5. *Conservative method. DEA is a model that by construction gives an interior approximation of the production possibility set, no ad hoc functional assumptions are needed*

6. *Protection for smaller operators since DEA model is calculated using non-decreasing returns to scale assumptions, meaning that operators below optimal scale get lower targets*

7. *Non-exploitation of economies of scales beyond the observed optimal scale in the DEA non-decreasing returns to scale model, albeit demonstrated in parametric models*

8. *Outlier tests at all stages identify and eliminate observations that correspond to technologies or circumstances that likely are not feasible for the average European operator.*

The e3GRID methodology is forward-looking and constructive in the following features:

1. *Variables selected for the final model are well justified, incentive compatible under a variety of regimes, incentive compatible for non-grid investment and costs under the Green Paper provisions and operationally implementable using a standardized data collection*

2. *The modular scope and methodology permits flexible support for national regulation, possibilities to tailor implementation to given initial conditions, specific stranded costs etc. thanks to the functional decomposition*

3. *The system operations model may be implemented in later stages while still maintaining the advantage of a consolidated framework for the performance assessment.*

Last but not least, the project represents the fruits of many hours of creative and constructive cooperation between operators, regulators, and consultants. In itself, this may be an output that shows not only efficiency, but effectiveness in realizing the objectives of the European energy directive.

Table of Contents

1. Organization and objectives 1
1.1 Introduction 1
1.2 Objectives 2
1.3 Link to project planning 4
1.4 Outline of the report 5
2. Process 6
2.1 Project organization 6
2.2 Deliverables 7
2.3 Starting and Ending Dates 7
2.4 Data reporting 8
2.5 Reference documents 9
2.6 Data collection and validation 9
2.7 Asset categorization 10
2.8 Cost standardization 11
2.9 Operator specific conditions 12
2.10 Approved condition A1: Activated land-fees 18
2.11 Approved condition A2: Activated investment taxes 19
2.12 Approved condition A3: Aesthetic maintenance 19
2.13 Approved condition A4: Power reserves 19
3. System description and modelling approaches 21
3.1 Functional view of transmission system operations 21
3.2 X Market Facilitation 22
3.3 S System Operations 23
3.4 P Grid Planning 23
3.5 C Grid Construction 24
3.6 M Grid Maintenance 24
3.7 F Grid Owner/Financing 24
3.8 A Administrative Support 25
3.9 Costs considered out-of-scope 25

3.10 Organizational structure 27
3.11 Role of the conceptual model 28
4. Methodology 30
4.1 Outline 30
4.2 Effectiveness, efficiency and performance evaluation 30
4.3 Technology and cost estimation 33
4.4 Non-parametric models (DEA) 35
4.5 Parametric approaches 38
4.6 Unit cost approach 43
4.7 Data cleaning, structural corrections and sensitivity analyses 46
4.8 Dynamic productivity and efficiency assessment 50
4.9 Fisher indexes 51
4.10 Malmquist methods 52
4.11 Summary and implementation 54
5. Parameter definitions 57
5.1 General 57
5.2 Interest rate 57
5.3 Asset lifetimes 59
5.4 Investment lifetime 61
5.5 Evaluation horizon 61
5.6 Reference year 61
5.7 Inflation adjustment 62
5.8 Salary cost adjustments 63
5.9 Overhead allocation keys 64
5.10 Asset grouping 65
5.11 Asset normalization weights 66
5.12 Exchange rate conversion 68
6. Model specification 69
6.1 Variable selection principles for efficiency analysis 69
6.2 Variable classification 70
6.3 Estimation procedure 71
6.4 Methods 73

6.5 Stepwise procedure 73
6.6 Results for stepwise additions 78
6.7 Results for quality indicators 78
7. Cost analysis 81
7.1 Overview 81
7.2 Cost development peers 86
7.3 Regional differences in cost development 91
7.4 Scope 91
7.5 Analysis of system operations costs 92
7.6 Analysis of market facilitation 97
7.7 Analysis of grid financing 100
7.8 Summing up 106
8. Benchmarking results 108
8.1 Model, estimation approach and sample 108
8.2 General findings 111
8.3 Model specifications 112
8.4 Static results 115
8.5 Model analysis 116
8.6 Dynamic results 126
8.7 Summing up 128
9. Sensitivity analysis 129
9.1 Scope 129
9.2 Sensitivity analysis on interest rate 129
9.3 Sensitivity analysis on scaling constant R 130
9.4 Sensitivity analysis on scaling constant Rc 131
9.5 Sensitivity analysis on asset weights 132
9.6 Sensitivity analysis on compensation indexes 140
9.7 Sensitivity to opening balances 141
10. Conclusion 143
10.1 Reported work 143
10.2 Further work 143

Appendix

Appendix A: OLS results – single addition
Appendix B: Log-linear results – single addition
Appendix C: Summary variables
Appendix D: Robust OLS results – single addition
Appendix E: Stepwise addition unit cost
Appendix F: OLS results single factor
Appendix G: Correlation results Y

Glossary

(Call) C	(Data collection for) Cost Related Information, e3GRID
(Call) Q	(Data collection for) Quality Related Information, e3GRID
(Call) S	(Data collection for) System Operations Information, e3GRID
(Call) X	(Data collection for) Grid Assets Related Information, e3GRID
(Call) Y	(Data collection for) Service Related Information, e3GRID
(Call) Z	(Data collection for) Operator Specific Conditions, e3GRID
(Function) A	Administration and Support
(Function) C	Grid Construction
(Function) F	Grid Financing/Ownership
(Function) M	Grid Maintenance
(Function) P	Grid Planning
(Function) S	System Operations
(Function) X	Market Facilitation
AIC	Akaike Information Criterion, model specification tool
BIC	Bayesian Information Criterion, model specification tool
BLS	(US) Bureau of Labour Statistics
CAPEX	Capital Expenditure
CE	Cost efficiency, cf. production theory 4.2
CEER	Council of European Energy Regulators
CEO	Chief Executive Officer
CMPA	Construction, Maintenance, Planning and Administration, scope in e3GRID
COGS	Cost of Goods Sold
(C)OLS	(Corrected) Ordinary Least Square [regression]
CPI	Consumer Price Index, inflation adjustors
CRS	Constant Returns to Scale, production functions
DEA	Data Envelopment Analysis, benchmarking method
DER	Distributed Energy Resources
DMU	Decision Making Unit
DSM	Demand Side Management
DSO	Distribution System Operator
EBIT(DA)	Earnings before Interest, Taxes (Depreciation and Amortisation)

e3GRID	Economic Efficiency for Electricity transmission GRIDs
EC	Efficiency Change, cf Dynamics 4.10
ECOM+	Efficiency measurement of Construction Operations Maintenance, international benchmarking of electricity TSOs for NRAs
ENS	Energy Not Supplied
ENTSO-E	European Network of Transmission System Operators for Electricity, TSO association
ETSO	European Transmission System Operators, TSO association
FDH	Free Disposability Hull, (DEA model)
FRH	Free Replicability Hull, (DEA model)
HVDC	High-voltage Direct Current, asset type
MA	Malmquist productivity index, cf. Dynamics 4.10
NDRS	Non-decreasing Returns to Scale, production functions
NG	Normalised Grid
NGTotex	Normalised Grid Totex proxy
NIRS	Non-increasing Returns to Scale, production functions
NRA	National Regulatory Authority
OECD	Organisation for Economic Cooperation and Development
OPEX	Operational Expenditure
PPI	Producer Price Index, inflation adjustors
SDEA	Stochastic Data Envelopment Analysis, benchmarking method
SFA	Stochastic Frontier Analysis, benchmarking method
TC	Technical Change, also called Frontier shift, cf. Dynamics 4.10
TE	Technical Efficiency, cf. production theory 4.2
TFP	Total Factor Productivity
Tobit	Regression model (Tobin, 1958) with a latent non-negative independent variable, used in efficiency analysis.
TOTEX	Total Expenses (= CAPEX + OPEX)
TSO	Transmission System Operator
UC	Unit Cost (i.e. cost per normalised grid unit)
UCTE	Union for the co-ordination of transmission of electricity, TSO association
VRS	Variable Returns to Scale, production functions

1. Organization and objectives

1.1 Introduction

1.01 This report constitutes part of services related to the development, execution, organization and final reporting of an international project for transmission system operations benchmarking, the European Efficiency analysis for Electricity GRIDs, e3GRID. This project was based on the Call for Tender 602a/8290/ *Internationaler TSO-Effizienzvergleich Strom*, issued October 19, 2007 by the Bundesnetzagentur, Bonn and commissioned 4235/830007 February 5, 2008.

1.02 The project was staffed by consultants from the SUMICSID group, Van Dijk Management Consultants SA and Tractebel Engineering SA.

1.03 Project coordinator for e3GRID was Dr Jan MOENS, jm@bvdmc.com, Director, Van Dijk Management Consultants.

1.04 The team from SUMICSID comprised Senior Associates Per AGRELL, prof. dr. per.agrell@sumicsid.com and Peter BOGETOFT, prof. dr, peter.bogetoft@sumicsid.com and Consultant Mathias LORENZ. This report is primarily authored by SUMICSID staff professors AGRELL and BOGETOFT.

1.05 The team from Van Dijk Management Consultants consisted of Dr Jan MOENS, jm@bvdmc.com, Marc Buyens and Carl Divry.

1.06 Team leader for Tractebel Engineering was Dr Jacques DEUSE, jacques.deuse@tractebel.com, the team also counted Dr Konrad PURCHALA.

1.07 The contracting party was Bundesnetzagentur in Bonn, Germany on behalf of 19 National Regulatory Authorities (NRA), cooperating in the Workstream-Incentive based Regulation and Efficiency Benchmarking (WS EFB) of the CEER Unbundling, Reporting and Benchmarking Task Force (URB TF).

1.08 The participating NRA belonged to the following countries: Austria, Cyprus, Czech Republic, Denmark, Finland, Germany (4 TSO), Hungary, Iceland, Italy, Lithuania, Luxemburg, (The) Netherlands, Norway, Poland, Portugal, Slovenia, Spain, Sweden and the United Kingdom (3 TSO). Hungary and Slovenia participated as NRA observers without TSO involvement in the project.

Background

1.09 The economic regulation of electricity transmission system operators (TSO) by national regulatory authorities (NRA) is governed by national energy acts implementing the Electricity Directive 2003/54/EC and the regulation EC 1228/2003 on cross-border exchanges. The Directive in particular aims at assuring (i) non-discriminatory access to networks and (ii) effective competition and efficient functioning of the internal energy market (IEM) through the effective monitoring and enforcement of the regulations by independent NRAs. One of the key tasks for NRAs is to fix or approve ex ante at least the methodology for determining the terms and conditions for the third-party access (TPA) to the network (art 20, 23, 2003/54 EC). Ineffective execution of this task may lead to abnormal returns on investment, low effort in quality provision, innovation and efficiency improvements and/or cross subsidies to other parties. Both in incentive regulation and in cost-recovery regimes, the regulator needs a thorough understanding of the cost drivers of their operators (cf Notes REG to 2003/54 EC, p. 5). For distribution networks in jurisdictions with numerous concessions or firms, this information can be gathered through the estimation of cost functions using national data. However, the wide scope of operations and the limited number of national firms (usually one) invalidates this approach for transmission services.

1.10 One particularly useful methodology in this matter is international benchmarking (Notes REG to 2003/54 EC, p. 6). Through the systematic and rigorous analysis of the costs and performance of other transmission system operators, a number of useful pieces of information can be obtained. First, a larger data set permits to distinguish the cost drivers that are purely exogenous from the endogenous cost decisions (managerial efficiency). This can be used to assess the current and past relative cost efficiency, which may inform tariff reviews under both high- and low-powered regimes. Second, the dynamic development (productivity growth) of cost efficiency for a relevant sample of TSOs is one of the key parameters in incentive regulation, the so-called X-factor in price- or revenue caps. For both outputs to be informative, valid and robust in actual regulation, a number of criteria have to be fulfilled, namely (i) optimal methodological application, (ii) access to an adequate set of validated data. The first criterion calls normally for the involvement or oversight of experts in the domain, the second for the concerted effort among several regulators, as in the current project.

1.2 Objectives

1.11 The overall objective for the e3GRID project was to *deliver regulatory sound estimates for the cost efficiency of European electricity transmission system*

operators, statically and dynamically, based on best-practice techniques using validated data for a relevant sample of structurally comparable operators. This primary objective can be broken down into four operational objectives:

- *Standardized static performance assessment*
  Based on a systematic task decomposition, e3GRID aimed at delivering a dual set of (absolute) unit cost and (relative) cost efficiency metrics that can be used to inform regulatory proceedings on the costs for critical functions for the transmission operations. The cost efficiency scores were calculated for 2006, with an appropriate methodology (frontier analysis, non-convex frontier analysis, or non-frontier review). The static scores are compatible with the CEER principles for grid expansion and include adjustments for country-specific differences of macro-economic and system character (salaries, service area, growth rates, density, purchasing power, system age, etc).
- *Standardized dynamic productivity results*
  Prior time-series data enabled the derivation of dynamic productivity improvement measures that express the annual cost efficiency change of any operator, decomposed into frontier change and catch-up effects. This information provided valuable insights into finding high performers and to inform regulatory setting of generic X-factors.
- *Applicable individual efficiency assessments*
  A specific review of operator specific factors and asset allow for a higher explicative value of the final scores. The e3GRID process was designed to allow a full range of submissions after reviewing preliminary results and then optional submission after all operator specific factors have been reviewed.
- *Individual regulatory support for application*
  The e3GRID process included time for an optional individual briefing with regulators to ensure that obtained results are interpreted with due caution and validity in a potential regulatory application. This included consideration of practical regulatory instruments such as the transformation of partial performance assessment to the period rate reviews, revaluation of regulatory asset bases and design of incentive systems.

Data validation measures

1.12 The e3GRID methods supported data validation in several complementary ways in order to ensure useful and informative results:

- *Transparency through the use of an online interface*
  Within the group communication was kept open to all members. As long as communication was not classified confidential all requests and explanations were available to all members on an online interface.
- *Transparency through open rulings on TSO specific cost*
  In the process of cost reporting every TSO had the possibility to claim

specific cost through a predefined systematic procedure. The techno-economic review in e3GRID verified that the specific conditions corresponded to significant, durable and exogenous increases in investment or operating cost. Approved specific cost drivers were communicated to all TSO, leaving them the opportunity to complementary reports.

- *Verifiability through systematic method*
  A clear submission, review and dissemination procedure limited the risks of strategic reporting and induced trust and confidence in the process and its results. The structured workshop interaction made sure that instructions are understood and agreed, that common problems were openly treated, leaving all participants with the same information and data submission possibilities.

- *Audit of submitted data prior to calculations*
  Cost data classified as out of scope were subject to a specific audit, either through an independent auditor appointed, or through a corresponding competence at the NRA. A specific auditing statement had to be presented for the cost report. This procedure guaranteed the integrity of the data for the further processing.

- *Optimal information access*
  All participating NRAs agreed on the same confidentiality agreement, warranting strict confidentiality to all data, implying that econometric teams could take part of any information material to reach highest quality results without risk of information losses. Ultimately, the regulatory authorities that were members of the project warranted for the correctness and timeliness of the data deliveries from their respective TSOs.

1.3 Link to project planning

Process

1.13 The current report (R3) documents the output of both intermediate reports in the project. In case of discrepancies with descriptions given in intermediate reports, the final report prevails. This final report (R3) contains the final static and dynamic results for selected models using DEA and other methods for specific functions.

1.14 The interim report *Static Results* (R1) concerned the evaluation of functions C, M and A. The assessment in R1 was based on data from data calls C (activities), X (assets), Y (service data) and Q (quality). R1 contained model development details and preliminary static results for frontier models of type Data Envelopment Analysis (Charnes et al. 1978) (DEA) and Stochastic Frontier Analysis (SFA).

1.15 The interim report *Dynamic Results* (R2) contained dynamic results for frontier models of type DEA.

1.4 Outline of the report

1.16 The project process, data collection and standardization are described in Chapter 2, the system description and the modelling for the benchmarking are discussed in Chapter 3, used benchmarking methodology are presented and defined in Chapter 4, key parameters are discussed and defined in Chapter 5, average cost estimations and model specification results are presented in Chapter 6. Descriptive results are provided for costs and development of some indicators in Chapter 7. The benchmarking results are presented in Chapter 8 followed by the sensitivity analysis in Chapter 9. The report is closed with a short summary in Chapter 10. . The technical details for the report are provided in Appendixes (A-G) attached in a separate document.

1.17 The report is final and public.

2. Process

2.1 Project organization

2.01 The e3GRID project, as any large undertaking involving the coordination of numerous countries and different stakeholders required a careful organization. To facilitate the organization and coordination of the project, it was subdivided into a number of elements: *84 Tasks in 8 Work Packages over 9 Phases*. The Work Packages (WP) were defined according to a specific function or technology in the project to delegate responsibility. The Phases related to the intervals between Milestones during which project management assured coordination between WPs. The interaction in the project was organized through an electronic project platform and through the organization of monthly progress meetings (here called Workshops). The outcomes of the project, finally, were defined as a set of deliverables. Below we provide an overview of the applied e3GRID planning through each of these elements.

2.02 The project process had seven components that partially overlap.

1. Methodological work based on econometrics, convex analysis, preference-ranking methods and efficiency and productivity analysis solidified the underpinnings of the model.

2. The Data Definition Guide and the Cost Definition Guides precised understanding and assured comparable date amongst the TSOs.

3. Established data collection routines between the E3GRID coordinators and the involved NRAs and TSOs. However, only NRAs were allowed to submit data sets, in order to induce higher compliance with the objectives and guides and to avoid information verification problems.

4. An interactive process based on monthly workshops each forwarding one element of the methodology towards the final result. Members were provided specific readings on methodological results, data definitions, preliminary results, weight sensitivities and elicitations, etc prior to workshops and time is allocated to ensure the full discussion of this material.

5. Ongoing data validation and verification with cross validation in the sample and asset studies with external data.

6. Specific audit, independent or NRA, for costs that were excluded from the exercise, enabling high trust in the cost data.

7. Final reporting, detailed confidential report and open anonymized versions of the report. Option to customize the report for regulators.

2.2 Deliverables

2.03 The e3GRID deliverables are given in Table 2-1 below. The reports R1 and R2 were technical interim reports that were also presented orally at workshops VII, VIII, IX and X. All reports were edited in English and distributed over the project platform to assure compliance with the confidentiality agreements and to verify receipt. The final report R3 was issued in a preliminary review version prior to final release. During the final phase, participating NRAs were invited to review the report and its findings, correcting possible errors and assuring that the wordings correspond to a common understanding.

2.04 In addition to the written reports, e3GRID also has also been supporting certain participating regulators through the project process S1.

Table 2-1 Project Deliverables.

Deliverable	*Description*	*Milestone*	*Date*
R1	Static Efficiency, interim report	M4	20/08/2008
R2	Dynamic Efficiency, interim report	M7	24/09/2008
R3	Final Report	M9	31/01/2009
R3C	Final Report, customized	M9	31/01/2009
S1	Regulator advisory session		28/02/2009

2.3 Starting and Ending Dates

2.05 The Starting Date was 30/01/2008.

2.06 The Ending Date was 28/02/2009.

2.07 The project milestones are listed in Table 2-2 below with an indication of possible associated deliverables or workshops.

Table 2-2 Project Milestones.

Milestone	*Date*	*Description*	*Deliverable*	*Workshop*
M0	30/01/2008	Project kickoff		W I
M1	10/03/2008	Start of data collection DS1		W II
M2	07/05/2008	End of data collection DS1		
M3	30/06/2008	Submission of Auditing Statements		
M5	30/07/2008	Submission of operator specific data DS2		
M4	20/08/2008	Static Efficiency, interim report	R1	W VI
M6	26/08/2008	Decisions on operator specific factors		W VIII
M7	24/09/2008	Dynamic Efficiency, interim report	R2	W IX
M8	28/11/2008	End of Calculations		
M9	31/12/2008	Draft Final Report	R3	W XII
M9	31/12/2008	Draft Final Report, customized	R3C	W XII

2.4 Data reporting

2.08 The information acquisition in e3GRID was made from NRAs, by eliciting information from TSOs, from CEER and by collecting and compiling information available from other sources. The presentation below is focusing on the external data collection.

a) *Call C – Activity data*
Scope and decomposition of costs to be reported in the benchmarking, methodology and definitions.

b) *Call X – Asset data*
Definitions of benchmarked system, asset definitions and data base classification.

c) *Call Y – Output indicators*
Data related to system services performed and their context.

d) *Call Q – Quality indicators*
Indicators of service quality in transmission, dimensions and definitions.

e) *Call Z' – Operator Specific Conditions and Assets (approved)*
List of operator specific conditions that have been expert approved, for optional submission by operators and inclusion in the final run R3.

f) *Call Z – Operator Specific Conditions and Assets*
Guidelines for submission of cost drivers, costs and asset types that have been omitted in calls C, X, Y and Q for some individual operator.

g) *Call S – Specification System Operations*
Complementary decomposition of Call C/S and X for specific activities. Template provided.

2.5 Reference documents

2.09 The data collection is based on the following reference documents, available until 15/03/2009 for authorized users at the project platform https://sumicsid.worksmart.net.

a) *Call C – Activity data*
Cost Reporting Guide (Call C), ver 1.4, 2008-04-15.
First release 2008-02-08.

b) *Call X – Asset data*
Electricity Transmission Asset Reporting Guide, ver 1.4, 2008-04-04.
First release 2008-02-07.

c) *Call Y – Output indicators*
Call Y, ver 0.2, 2008-03-31.
First release 2008-03-28.

d) *Call Q – Quality indicators*
e³GRID Call Q: Quality Indicators, 2008-03-03.
First release 2008-02-08.

e) *Call Z' – Operator Specific Conditions and Assets (approved)*
Data Call for Operator Specific Conditions (Call Z), ver 0.3, 2008-03-10.
First release 2008-02-28.

f) *Other*
Project Plan, ver 1.9, 2008-11-18.
Data Specification, ver 0.9, 2008-09-01

2.6 Data collection and validation

2.10 The cost and asset data specified in Calls C and X above have been collected through the NRAs for each participating TSO from M1 (2008-03-10) to M2 (2008-05-07), with auditing statements for specific costs due 2008-06-30. Indicators for Call Y and Q were collected by the consultants from public databases (mostly EUROSTAT) and from NRAs until 2008-07-28. Submission of information for possible inclusion as operator specific conditions (Call Z) was open from 2008-06-20 to 2008-07-30 (M3).

2.11 The validation of the data has been made in three levels. First, the submitting NRA have reviewed the data after their submission in order to attain consistency and consolidation with regulatory accounts. Second, external or NRA-internal auditors have reviewed cost items that are left outside of the benchmarking, specified in a list in Call C with the possibility of using a standardized auditing statement for their reports. Third, the consultants have verified the compliance of the data compared to the instructions using tools and templates with immediate recognition of omissions and inconsistencies. The verified data have then been validated by a technical and/or an econometric team, depending on agreements and type of data. In this validation, the plausibility of technical installations, the allocation of activities to functions, the consolidation of the accounts to annual accounts and the correspondence to other published material on staff and activity information have been checked. This process, lasting from 2008-05-07 to 2008-07-28, lead to numerous interactions with NRAs regarding data, including notified changes to assets, costs and staff numbers in both directions. In the case a validation revealed incomplete data that would adversely affect the quality of the benchmarking or the inclusion of the TSO in the first run, the validation teams made necessary approximations that were validated with the respective NRAs.

2.12 The impact of IFRS versus prior national cost accounting standard has been assessed through a questionnaire presented in draft 2008-05-05 and collected 2008-06-19. A document was also prepared to identify potential areas of impact for the e3GRID benchmark, concluding that most differences concern elements in the balance sheet and the financial costs (F). Support for this conclusion was also given by the questionnaire since 15 of 17 respondents stated small or no differences for the benchmark.

2.7 Asset categorization

2.13 The transmission asset classification in Call X above is a relatively detailed approach based on key components recognized as major cost drivers. It is directly linked to the estimation system for relative normalization factors (weights) and abstracts from specifics to reach a tractable, yet nuanced image of the grid and its development over time. The categorization is not the only possible, but its usefulness has been demonstrated by its use in the ECOM+ benchmarkings 2003 and 2005. Compared to ECOM+, the asset categorization in e3GRID is enhanced with the number of lines per route (single, double, etc), by an additional class for control centers and the collection of tower information. The establishment of the asset categorization was naturally made prior and independently of the collection of asset or cost data for the project.

2.8 Cost standardization

2.14 The cost and investment information emanating from Call C above was processed through a standardization process schematically represented in Figure 2-1 below. The objective with the standardization process was to prepare the comparison material based on structurally comparable units under comparable operating conditions.

2.15 The operating costs were allocated to functions based on the type of activities they refer to, guided by the functional definition in Call C. Costs leaving the decomposition (out of scope, cf. subsection 1.3.9) were subject to specific audits. Within the functions, costs were reported by cost type, separating costs that are subject to specific adjustments (depreciations for grid vs non-grid assets, manpower compensation). While the depreciation of grid assets is deducted from the operating cost, direct manpower costs were corrected for national (regional) labour cost differences by an index (cf. subsection 5.8). Finally, the obtained sum was converted to EUR of 2006 value to form benchmarked OPEX using an inflation adjuster (cf. subsection 5.7).

2.16 The investment stream data were validated for the type of pre-treatment that may be underlying (nominal or revalued amounts, indexation or not). For each investment year, the sum of investments was transformed to the purchasing value of 2006 through the use of an inflation adjustment index (cf. subsection 5.7). The investments were then periodized by a real annuity using a standardized interest rate (cf. 5.2) and weighted asset life time (cf. subsection 3.15.10). Finally, the annuity stream was converted to EUR as benchmarked Capex.

2.17 Benchmarked TOTEX was formed as the sum of benchmarked OPEX for the relevant functions and benchmarked Capex.

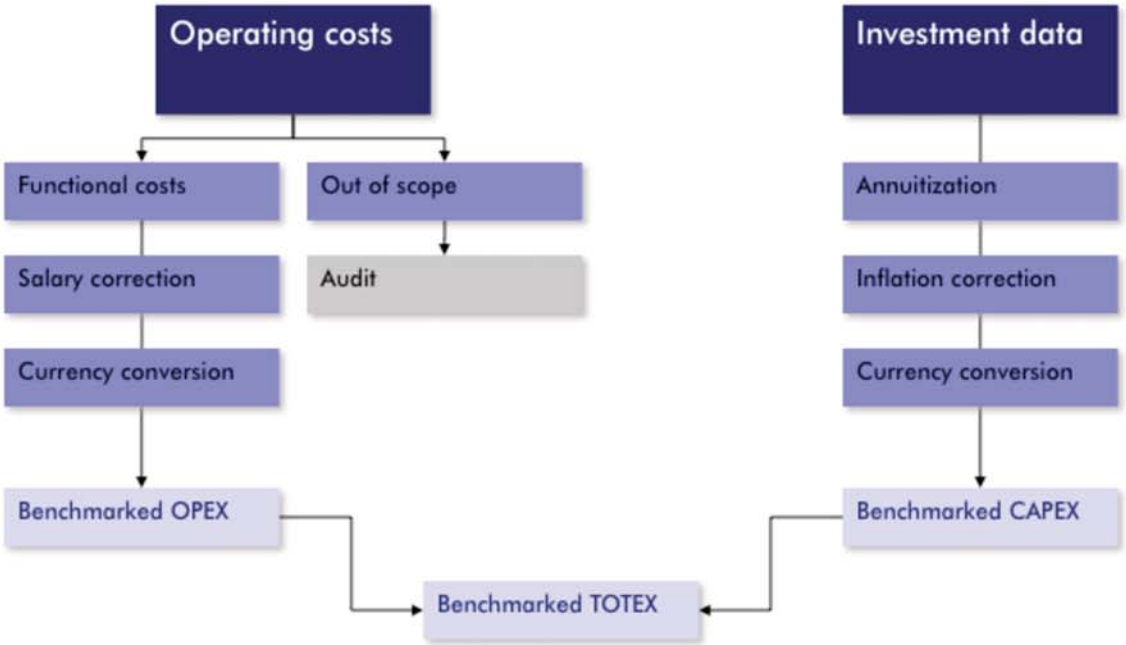


Figure 2-1 Cost standardization process in E3GRID.

2.9 Operator specific conditions

Organization

2.18 In addition to information collected through the central calls (C, Q, X, Y, F, S), the participants could complement the data for the study by submitting candidate variables and factors (claims) for potential inclusion as *operator specific corrections*. This process and the confidentiality provisions regarding the claims were more thoroughly described in the guide *Data Call for Operator Specific Conditions (Call Z)*. The Call Z process was overseen by Dr Jacques Deuse and the review work was done by a technical team and an economic team under the direction of Prof. Per Agrell. subject to.

2.19 The collection of candidate factors constituted dataset 2 (DS2), collected voluntarily from milestone 2 (M2, end of data collection DS1) until milestone 5 (30/07/2008) using a specific template. The results of the review process below were announced to the participants at workshops 7 and 8 (W7 20/08/2008, W8 26/08/2008). Each participant had the opportunity to submit information for corrections under the definitions of approved operator specific conditions by 24/09/2008 as the optional dataset 3 (DS3). The results in this report are based on DS3 as far as submitted data has been validated in accordance with the Guide and the Project Plan. The process is outlined below with explicit references to the Project Plan.

1. First submission of preliminary claims, Z' (art 3.02)

2. NRA review of claims Z' (art 3.03)

3. External review of claims Z' (art 3.04)

4. Disclosure of conditions Z' (art 3.05)
   –In motivated decisions on each submitter on Worksmart (14-25/08/2008)
   –List of submitted claims at W7 (art 3.02, PP art 5.05)
   –Process presented at W7 (NRA) and W8/M6 (26/08/2008)
   –Approved categories in specific document on Worksmart (29/08/2008)

5. Complementary submission Z (DS3)
   –Due at M7 for inclusion in the Final Report (R3) (art 3.07)

2.20 The organization and processing of the operator specific claims in the e3GRID project were conceived to accommodate motivated suggestions for omitted factors and conditions, as described in detail below. However, the principal objective of the process was to obtain structural comparability in the general study and to permit the derivation of robust, interpretable and feasible results for the scopes of models selected. It was not intended to investigate the justification or not of particular costs and decisions in detail, nor to intervene in the regulatory rulings on the optimal level of certain costs or services. Although applying due diligence in its processing of cost claims, reviewing submitted documentation and soliciting NRA information, the expert teams also had to exercise judgement with respect to resource allocation per claim in order to maintain the planning in the project plan. Nevertheless, the process must be considered as an effective and efficient mean to solicit this additional information without jeopardizing the objectives of the benchmarking with respect to results, timing and budget, or supplanting regulatory rulings by obscure *ad hoc* decisions by consultants.

Background

2.21 To allow fair comparisons and relevant modelling, we needed to account for a range of *complicating factors*, i.e. factors that the TSOs do not control and which may have significant impact on their ability to perform cost-efficient services. The complicating factors could for example reflect:

- the climate and other operating conditions which might render the construction, operation and maintenance more difficult and costly
- the environmental restrictions which may severely limit the firms' choice of technical solutions
- the interconnectedness of the country, which could have a considerable impact on network configuration and operating practice.

- the universal service obligations that are imposed on the different companies
- the operator specific and international market structures in generation and consumption that affects the companies and on which they have limited control

2.22 To allow fair comparisons and relevant modelling, we also needed to account for a range of *complicating properties*, i.e. properties that the companies may affect but which are neither inputs nor outputs in the usual sense. Rather, the complicating properties capture different properties of the inputs or outputs. The complicating properties for an electricity TSO may for example include:

- Differences in energy reliability levels
- Differences in power reliability levels
- Differences in the service restoration (fault detection and correction) levels
- Differences in customer satisfaction

Criteria

2.23 Given the number of TSOs in any detailed study and the informational asymmetry inherent in the benchmarking of national monopolies, all individual conditions that are, or have been, applicable to the service cannot be covered. Instead, participating TSOs in international studies have been invited to submit a statement of alleged complicating factors. To qualify for inclusion in the study as an operator-specific allowance, the cost driver had to have *exogenous, durable and sizeable* impact on benchmarked cost.

2.24 In addition, factors that are indeed valid in terms of the relevance criterion, but that were common to all participants, were excluded. If a factor is shared among all networks, it can no longer be considered an operator-specific factor but part of the general cost drivers (in the data sets X, Y, or Q) and subject to the standard relevance tests. Examples of such factors are cost increases related to transit loads and decentralized generation.

2.25 Also, factors that are already accounted for via the standardization of costs and assets (Calls C and X) were excluded. Examples of this could be right away fees (which may depend on operator specific land prices), or the installation of excess capacity (which can depend in part on climate conditions).

2.26 Likewise, there was no reason to make claims of operator specific cost properties that were already accounted for via the quality and performance indicators (Call Q and Y). Examples of factors that may have been excluded for this reason could be operator specific high reliabilities or operator specific high population density. Claims related to specific environmental conditions that were included, directly or by proxy, in Call Y were also investigated statistically already in the interim report R1. Examples here are the prevalence of lakes, road, forest and variations of density. I.e., if a specific factor for which data existed was not shown to exhibit a significant cost-increasing effect on benchmarked cost, an analogous claim by a TSO was rejected unless specific circumstances were shown.

2.27 To sum up, the operator specific conditions were intended as a residual in which factors that were not covered by the other calls (X, C, Q) and which could not be corrected for via the general performance indicators (Y), and which have *exogenous, significant and durable* impact, could be elicited.

Process

2.28 The review process was organized in four stages as illustrated in Figure 2-2 below. The first step filtered on *eligibility* of the claim on elementary components of the information submitted. The second step for eligible claims involved the actual review with respect to the three criteria of *exogeneity, materiality* and *duration*. Claims that passed on the three criteria were resubmitted to the NRAs in preliminary assessments with *requests for endorsement* (if relevant) of submitted information, in particular with respect to exogeneity. Endorsed claims from this step were reviewed for possible *inclusion in ongoing revisions* of the general model or data collection. Finally, the approved and endorsed claims that were not subject to model extensions were declared *approved* and announced to the participants for possible resubmission in DS3.

Eligibility

2.29 A submission under Call Z had to concern a specific identified cost, asset or valuation included in the benchmark and be accompanied by an estimate of its impact on the operator in terms of cost and/or performance dimensions relevant to the study. Several submissions were, in fact, informative statements regarding the reporting of the operator within the benchmarking and did not contain any identifiable claim. Some operators desired more detailed subdivisions of asset classifications, whereas some thought the reporting requirements were too heavy. Other viewpoints included alternative asset classification bases and limits. However, given the review period for the Asset Definition Guide at the outset of the project and the interactive data collection period for DS1, it was clearly infeasible

to change such design features without very heavy reasons, which were not present. Submissions of this character were declared ineligible and dismissed without further review.

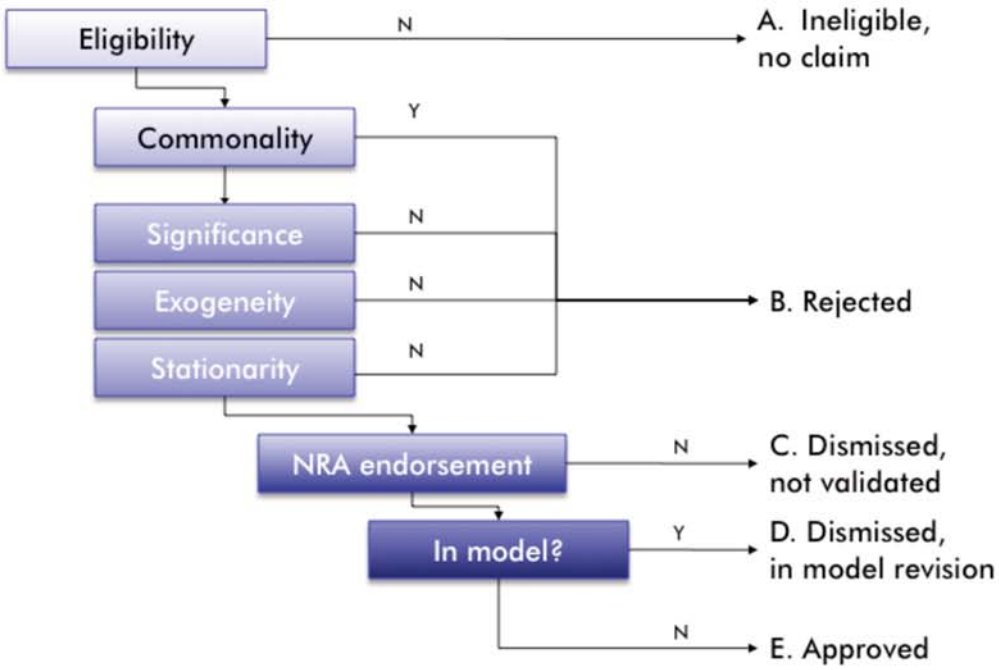


Figure 2-2 Review process operator specific claims (Call Z).

Expert review: Criteria

2.30 The purpose of the entire Z process is to inform the benchmarking of specific conditions that may affect the performance of an individual operator (or a group) that are

1. exogenous
2. significant
3. durable

1. Exogeneity

2.31 Claims that refered to conditions, equipment and /or operating standards that may have impact on Capex and/or OPEX but that are the result of an internal decision making process in the firm (e.g. substation design, rail access, investment policies) were considered endogenous conditions. Crucial for the determination of the exogeneity was the existence of a legal or regulatory obligation to perform a non-standard task/cover the

cost *in spite* of an explicit interest on behalf of the operator to adopt a different policy.

2.32 Several claims were rejected on this criterion. Examples included equipment choices that might not be cost-optimal (today) but that did not result from any exogenous involvement. The prerogative of interpretation of exogeneity was given to the NRAs.

2. Significance

2.33 Claims that indeed were exogenous and stationary had to exceed a materiality criterion. The criterion applied was 3% of benchmarked cost by claim (not cumulated). Benchmarking is a comparative process that is intrinsically associated with averaging conditions and simplifying to pick up the important differences in relative performance. Deviations (up and down) are naturally part of any collection of asset or cost-service observations. A selective reporting of positive small deviations would of course lead to a biased estimate of the true costs for both the operator and the sector. In addition, the materiality criterion served as an indicator of the level of deviations for which the external team mighty be more effective than the NRA in judging against international average and best practice. Smaller differences, if indeed relevant when all effects are factored in, may and should be addressed by the NRAs within its applicable regulatory framework.

2.34 Several claims were rejected on this criterion, with or without validation of the cost estimated submitted with the claim. The materiality criterion is compliant with the German network regulation (ARegV, section 15 (1)).

3. Duration

2.35 Claims that refer to restructuration, accidents, refurbishing, upgrading of assets etc are often related to sporadic events. In terms of insurable events, no correction was made since insurance premiums were included in the benchmarked costs. For non-insurable events above the materiality threshold, the result was interpreted by the NRA that is likely well-informed about the cause and the impact of the results, not the consultants. The criterion served as to direct the process towards operator specific conditions, not out-of-scope or exceptional events for which other procedures exists.

2.36 Few claims were investigated on this criterion and none was rejected uniquely based on this criterion.

Outcome

2.37 The results of the review process are listed in Table 2-3 below. As seen from the table, the evaluation has been a relatively strict application of the criteria above. As stated elsewhere, this does not mean that the factors in themselves are not complicating or cost-increasing, nor is it a recommendation for NRAs to disregard these costs as imprudently occurred. An extensive application of individual correction factors, based on confidential ad hoc material not included in the general benchmarking would jeopardize the methodological transparency of the benchmarking process and interfere in what is a necessary and vital part of the regulator-operator interaction. Worse, the outcome of the study would have to be interpreted, not based on NRA-available national information, but on an estimation of the relative indulgence to operator-specific claims from other operators relative to the response to claims from the national operator.

Table 2-3 Outcome of review process for operator specific claims.

Type	#	Decision	Economic	Technical
A	14	Not eligible	8	6
B	44	Rejected on criteria 1-3	17	27
C	2	Dismissed by NRA	2	
D	14	Dismissed (model feature)	13	1
E	4	Approved	3	1
	78		43	35

2.10 Approved condition A1: Activated land-fees

2.38 A1 concerned activated land-fees, easements, right-of-way charges such as those specified under the provisions of Call C, art 3.03 and 3.04 when expensed. The claim was justified by past significant amounts capitalized of settlements paid to land-owners following settlements or legal expropriation proceedings.

Application

2.39 TSOs could deduct from the investment stream in each applicable year the amount corresponding to activated land-owner compensations (Call C, art 3.03) and easement fees (Call C, art 3.04).

Requirement

2.40 Application by audited account, or in default, by the application of a conservative share based on an externally (auditor and/or NRA) verified sample.

2.11 Approved condition A2: Activated investment taxes

2.41 A2 concerned activated investment taxes and duties such as those of Call C, art 3.05 when expensed. The claim was justified by past significant amounts of capitalized investment taxes under national fiscal laws.

Application

2.42 TSOs could deduct from the investment stream in each applicable year the amount corresponding to activated taxes and duties of the kind referred to in Call C, art 3.05.

Requirement

2.43 Application by audited account, or in default, by the application of a conservative share based on an externally (auditor and/or NRA) verified sample.

2.12 Approved condition A3: Aesthetic maintenance

2.44 A3 concerned costs in excess of normal maintenance of towers or other grid assets due to environmental law or other regulation. The original claim concerned a TSO being obliged to paint towers in colors and with frequencies beyond normal maintenance due to national environmental law.

Application

2.45 TSOs could deduct from the benchmarked cost in M in each applicable year the amount corresponding to the difference between normal painting for corrosion protection (if applicable) and the actual amount spent. The amount was reported as Out-of-scope.

Requirement

2.46 Application by audited account, or in default, by the application of a conservative share based on an externally (auditor and/or NRA) verified sample.

2.13 Approved condition A4: Power reserves

2.47 A4 concerned costs absorbed by TSOs as residual claimant for the primary and/or secondary power reserve. The justification was a proven heterogeneity in the statutory obligation of the operators to provide for

and finance primary and/or secondary power reserves under what is reported as System Operations (S) in the study. Some TSOs are obliged to procure primary and secondary control reserve without symmetric pass-through of costs. The amounts involved are substantial and the arrangement is not transitory.

Application

2.48 Costs for primary and secondary control reserves procured using competitive sourcing under legal obligations were specified separately and excluded from the general evaluation of S.

Requirement

2.49 Complementary information (Call S) was collected from all TSOs regarding the obligations for power reserve and the amounts paid for such procurement (if applicable). Validation was made by NRA endorsement and consolidation to regulated and/or public accounts.

3. System description and modelling approaches

3.01 In this chapter, we provide a conceptual model of the activities of a TSO and we delineate the focus of the different analyses performed in this project.

3.1 Functional view of transmission system operations

3.02 The fundamental objective of a transmission system operator is to ensure the electrical stability of the interconnected system so that electrical energy can be transported from generators to distribution networks. The operator provides open access to the transmission system, monitors and controls system operations to ensure a moment-to-moment energy balance, manages congestion, schedules generation (or reviews the technical feasibility of schedules submitted by others), acquires ancillary services such as disturbance reserves and voltage support, and plans or approves requests for maintenance of transmission and generation facilities. Many system operators also administer spot and real-time balancing energy markets. These operators generally perform metering, accounting, settlement, and billing for the markets, but may also initiate, enforce or administer market instruments related to congestion, supply safety and load control.

3.03 By distinguishing seven important functions or roles, the autonomy and independency of an operator may be put in a correct context to enable, among other things, performance assessments (cf. Figure 3-1 for the six core functions). The functions are:

X ***Market facilitation***
S ***System operations***
P ***Grid planning***
C ***Grid construction***
M ***Grid maintenance***
F ***Grid owner/financing***
A ***Administration and support (including central management)***

3.04 The first three functions are *strategic functions* with long-term impact on system performance. The functions C and M are *operational functions* with comparatively fewer long-term system-wide impacts. The ownership is normally tightly connected to regulatory and institutional practices.

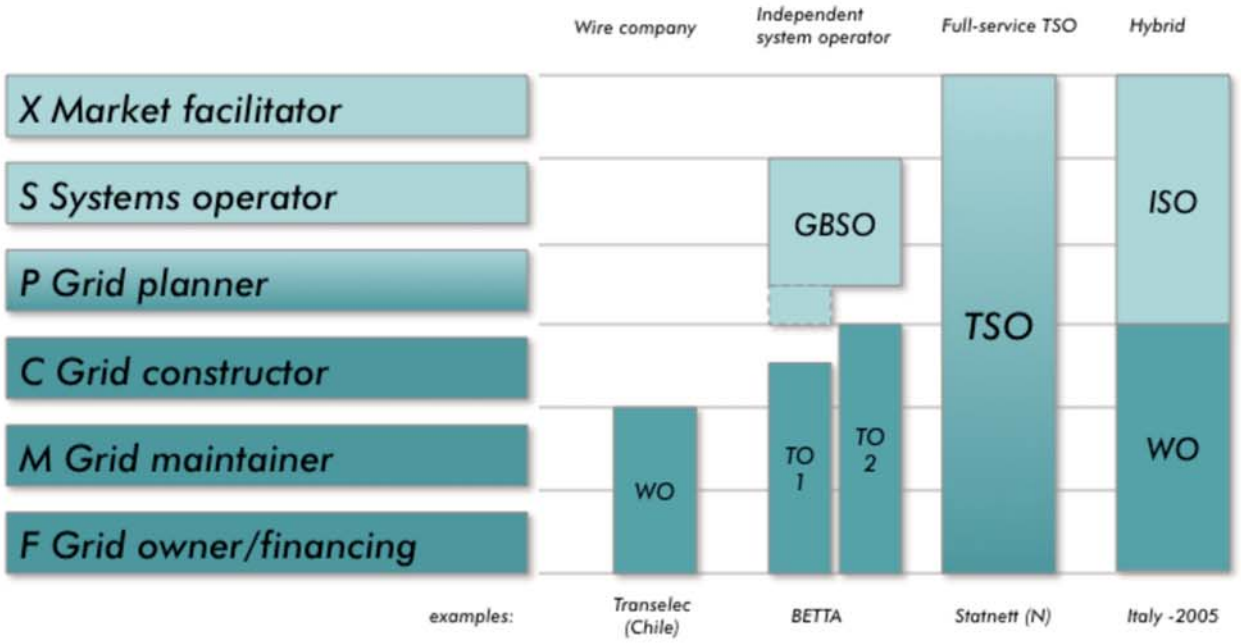


Figure 3-1 TSO Functions and Organizational Type.

3.2 X Market Facilitation

3.05 The establishment, monitoring and enforcement of an advanced electricity exchange require to some extent the informational support of the transmission system operator. The TSO will necessarily be involved in the final settlement of the delivery of the good and may also pose additional fees for its transmission. Independent market operators normally handle the clearing, trading and management of financial instruments for the electricity market. The activities for this function involve all information costs and direct resources related to the management, facilitation or administration of market places, including measurement, calculation and dissemination of price signals (node prices, price zones), preparing annual surveys and forecasts for use by the market's current and potential players and to illustrate compliance with public service obligations, information for settlement of claims and contract flows from exchanges, backup agreements and research and development into market functioning, mechanisms and contracts. If applicable, responsibilities related to the information flows to relevant markets (green certificates, renewable fuels, DSM, DER, preferential feed-in tariffs) are also considered market facilitation.

3.06 Costs and revenues related to transitional or permanent retail engagements, such as procurement, billing, losses and resale of energy to captive or non-captive clients are considered specific cases of market facilitation.

3.3 S System Operations

3.07 The purpose of system operations is to ensure the real-time energy balance, to manage congestion, to schedule and dispatch generation (or to review the technical feasibility of schedules submitted by others), to perform failure analysis and detection, to manage the availability and coordination for preventive and reactive reparations, and to acquire ancillary services such as disturbance reserves and voltage support, maintaining technical quality and balance within the coherent electricity supply system, also ensuring that the necessary supply capacity for physical regulation of the system is available. System operations are subject to the limitations of the existing grid, but information arrangements and tariff structure may either aggravate or alleviate congestion management problems. It also deals with the day-to-day management of the network functionality, including personnel safety (instructions, training), equipment security including relay protection, operation security, coordination with operations management of the neighbouring grids, coupling and decoupling in the network and allowances to contractors acting on the live grid. Given its central position in terms of market and technical information, the competence and independence of the system operator will have short- as well as long-term effects on social welfare. System operations may entail delegating operational balance services to subordinate (regional) transmission coordinators with limited decision rights.

3.08 In particular, we refer all costs and revenues from national and international congestion management to system operations, as well as all direct and indirect costs related to balance markets.

3.09 Costs, imposed or not, for spinning reserves, capacity provision or out-of-market guarantees or caps in case of power shortage are for the purposes of this study referred to as system operations.

3.4 P Grid Planning

3.10 The analysis, planning and drafting of grid expansion and network installations involve the internal and /or external human and technical resources, including access to technical consultants, legal advice, communication advisors and possible interaction with governmental agencies for pre-approval granting.

3.11 Grid planning also covers the general competence acquisition by the TSO to perform system-wide coordination, in line with the Third package and the ENTSO tasks. Consequently, costs for research, development and testing, both performed in-house and subcontracted, related to functioning

of the transmission system, coordination with other grids and stakeholders are reported specified under grid planning P. This provision also includes membership fees to research organizations and sector organs such as UCTE, ETSO, IEEE, NordEl etc.

3.5 C Grid Construction

3.12 The grid constructor implements the plans from the grid planning once all necessary authorizations have been granted. Construction involves tendering for construction and procurement of material, interactions, monitoring and coordination of contractors or own staff performing ground preparation, disassembly of potential incumbent installations, temporary site constructions and installations, installation of equipment and infrastructure, recovery of land and material, test, certification and closure of the construction site.

3.13 In particular, all expenses related to site selection and environmental impact analyses are classified as grid construction since this cost normally is activated with the investment.

3.14 Note that costs related to the expropriation of land for construction, remodeling or dismantling of grid assets, including direct legal costs for the process and costs potentially paid to claimants as consequences of legal proceedings are to be specified separately as Out-of-Scope.

3.6 M Grid Maintenance

3.15 The maintenance of a given grid involves the preventive and reactive service of assets, the staffing of facilities and the incremental replacement of degraded or faulty equipment. Both planned and prompted maintenance are included, as well as the direct costs of time, material and other resources to maintain the grid installations. It includes routine planned and scheduled work to maintain the equipment's operating qualities to avoid failures, field assessment and reporting of actual condition of equipment, planning and reporting of work and eventual observations, supervision on equipment condition, planning of operations and data-collection/evaluation, lawn moving, tree cutting and emergency action. Indirect functions related to maintenance, i.e. facilities management, warehousing, sparepart management, etc are also included in M.

3.7 F Grid Owner/Financing

3.16 The grid owner is the function that ensures the long-term minimal cost financing of the network assets and its cash flows, including debt

financing, floating bonds, equity management, general and centralized procurement policies, leasing arrangements for grid and non-grid assets, management of receivables and adequate provision for liabilities (suppliers, pensions, etc). Eligible costs here are directly calculated from the Annual report and derive from the cost of debt and equity financing. The Grid Owner function is subject to specific review and will not be included in the general assessment of controllable costs for the TSO, as the financial costs predominantly are decided as a result of direct regulatory rulings on e.g. credit ratings, equity-ratio requirements and WACC allowances.

3.8 A Administrative Support

3.17 The costs for administrative support by direct definition include the non-activated salaries, goods and services paid for central and decentralized administration of human resources, finance, legal services, public relations, communication, organizational development, strategy, auditing, IT and general management. The direct costs for executives, CEO, Board of Directors or corresponding are included in A, as are fees and honoraries paid to consultants and experts engaged in project not directly assigned to any other function. In terms of direct costs, the A function also has a residual role, meaning that any and all non-activated cost that is not assigned to any of the six core functions of the TSO or listed among items eligible for Out of Scope exclusion, is considered a cost for unspecified support A.

3.18 The idea behind the administrative support function is to create neutrality between different organizational form for support. As many of the support functions may be obtained through leasing or service contracts that include a non-specified cost for the use of non-grid assets, the corresponding depreciation on non-grid assets (subdivided as below) is included in the cost for A.

3.19 The costs for administration A can in general be assigned to the respective value-added functions using direct or indirect allocation methods. A standardized allocation system was developed for the project using staff intensity (full-time equivalents). However, as discussed in subsection 5.9, the allocation keys were not used and all administrative expenses were included in the frontier benchmarking.

3.9 Costs considered out-of-scope

3.20 As the objective of the e3GRID study is to compare the relative performance of TSOs in Europe, it requires a set of structurally comparable units. Although corrections can be made for many specific conditions, such

as labor cost differences, equipment specifications and service requirements, certain costs are intrinsically related to national cost levels and legislations. Including such costs in the benchmarking, even after some partial adjustments, would potentially create misleading targets and decrease the applicability of the results. Hence, certain costs are to be specified and excluded in their entirety from the study. However, this also means that their amount will have to be endorsed by an accompanied statement from an auditor or equivalent.

3.21 The following cost types are out of scope: all costs related to material and immaterial assets related to land or buildings, all types of taxes and levies on properties and activities. More specifically, this concerns:

1. *Land-owner compensation*
2. *Right-of-way and easement fees*
3. *Taxes on property and operation*
4. *Rents and leases of land and buildings*
5. *Depreciation on land, buildings and improvements*

Land-owner compensation

3.22 Non-activated payments to property owners as a result of a legal process (e.g. expropriation or compensation agreement), procurement or negotiation, related to the damage or injury of land, and /or the right to use land for the activities of the TSO. The direct costs for judicial assistance, court fees etc for legal processes (terminated or non-terminated) related to the use, damage or injury of land for the activities of the TSO are also out of scope.

Right-of-way and easement fees

3.23 Non-activated payments to third parties as a result of a legal process (e.g. expropriation or compensation agreement) or negotiation related to the use of specific land or installations (roads, waterways) for the activities of the TSO.

Taxes and levies

3.24 Non-activated state, municipal and regional taxes, levies and public fees paid for the ownership of specific assets (e.g. property taxes, packaging), to use of specific processes (e.g. environmental levies), for investments and procurement (stamp taxes, legal fees, customs), for non-claimed value-added taxes (foreign VAT), and taxes paid on declared annual profits. Note that taxes, charges or fees related to salaries, pensions and other payroll items are considered in scope.

Rent of land, buildings and infrastructure

3.25 Rents and leasing fees paid for the right to use land, buildings, building improvements and/or land/building infrastructure are excluded. However, rents that include other assets or equipment, such as vehicles, communication and computer equipment are in scope.

Depreciation on land, buildings and improvements

3.26 Depreciations on all land (if applicable), buildings, building improvements, land/site improvements, and building infrastructure are part of the out of scope. However, depreciation related to vehicles, furniture and equipment related to joint or non-grid use, including communication and computer equipment are in scope of the study.

3.10 Organizational structure

3.27 To summarize the framework and prepare for the cost allocation and benchmarking exercises below, consider the organizational chart for a full service transmission system operator in Figure 3-2 below. The activities are divided into functions under the joint management of a CEO, answering to a Board of Directors or corresponding. The central management is supported by some off-line support unit that performs joint activities, monitors and reports implementation of central policies, typically strategic planning, communication, human resources, and legal services. Each function performs the activities previously discussed using staff, fixed and variable resources. The e3GRID study covers in principle all costs except the Out of Scope items, but using different models certain costs.

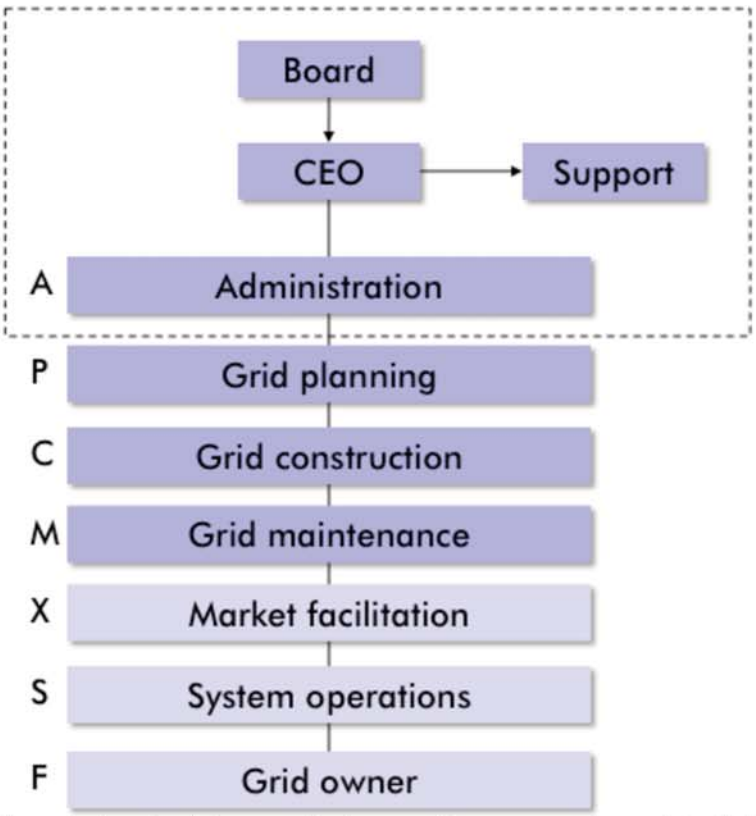


Figure 3-2 Organizational chart of transmission system operator. Administration A includes support functions, board and CEO.

3.11 Role of the conceptual model

3.28 The conceptual model developed above served several purposes. Most importantly, it has guided the collection of cost data and was used to delineate the focus of the different analyses.

3.29 The major focus in this report is on the Construction (C), Maintenance (M), Planning (P) and Administration / Support (A) activities that are subject to frontier modelling. The activities Market facilitation (X) and System operations (S) are subject to a limited review due to their heterogeneity, Grid financing (F) is included for comprehensiveness.

3.30 In our attempt to model and compare the activities across TSOs in this study, we have in addition used a multiplicity of modelling and estimation approaches. We shall describe these in the next chapter before turning to the specific results.

3.31 The role of the multiple approaches and estimations was both to strive for a comprehensive evaluation, i.e. to get evaluations of a large part of the controllable costs, and to safeguard against the limitations of any

particular method and we have therefore, as a general approach, combined the multiple results with a cautious attitude.

3.32 A particular motivation for being cautious was the social importance of the TSO activities and the fact that unreasonable savings leading to lower quality and a less effective market place may have large indirect social costs. Hence, lower transmission tariffs are beneficial for society only to the extent that they are the result of improved TSO efficiency (or perhaps lowered profit margins) and not as the result of unattainable targets forcing the TSO to compromise their important roles. For more on the different roles cf. the Charter of Accountability (Agrell, Bogetoft, 2002b).

4. Methodology

4.1 Outline

4.01 In this chapter, we provide an introduction to state-of-the-art benchmarking methods. Since there are by now many textbooks covering the different types of benchmarking models and since many of these techniques are now used internationally in regulation at a routine basis, we do not seek to cover all possibly relevant methods in details.

4.02 Our aim is to provide a basic vocabulary and idea about the approaches for readers without much previous exposure to this literature. Hence, we focus on the methods used in this report. Also, our aim is to point to some of the difficulties of these methods and the pre- and post analyses, e.g. initial data cleaning and post analyses sensitivity analyses, that are needed not the least in regulatory applications.

4.2 Effectiveness, efficiency and performance evaluation

4.03 Ideally, a performance evaluation should measure effectiveness i.e. the extent to which it is possible to improve the overall goal we give to the evaluated. In reality, this is complicated since most organizations pursue multiple goals that are not easily aggregated. Moreover, we generally lack information about the possible transformation of resources to services of real organizations.

4.04 In real evaluations or benchmarking exercises, we therefore go from measuring effectiveness to efficiency, e.g. the ability to provide the same or more services with the same or less resources. Also, we go from absolute efficiency by measuring against an empirical norm as established by comparison with other units or by including information derived from actual practices. The latter corresponds to the establishment of an empirical model, and the former to the measurement of efficiency relative to the estimated model.

4.05 To be slightly more formal, assume that an organization, for now a TSO, has delivered a vector of outputs (services) y_i using a vector of inputs x_i. Also, let the goal of the organization be to maximize U (x_i,y_i) and the feasible combinations of (x_i,y_i) is the set T. Also, let T* be an empirical approximation of T.

4.06 The logical moves from effectiveness to efficiency to relative efficiency can now be illustrated as in Figure 4-1 below

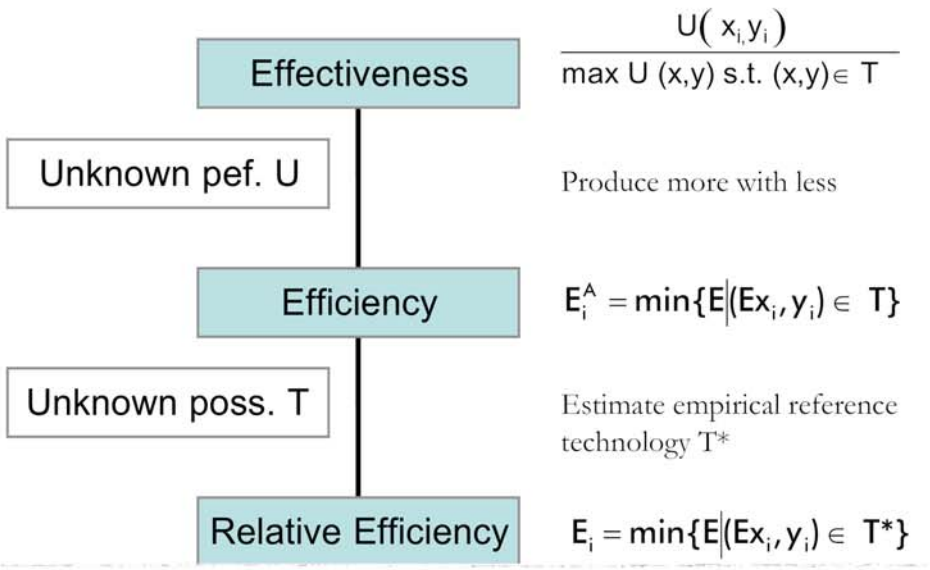


Figure 4-1 From effectiveness to relative efficiency

4.07 In this chapter we shall describe different ways in which we can establish the empirical model, or the estimated technology, T* above using statistical, programming, engineering and accounting methods. Before turning to these more specific details, however, it is useful to discuss the problem of measuring efficiency relative to a given technology.

Technical efficiency, cost efficiency and sub-vector efficiency

4.08 The literature suggests many possible productivity measures but for the purpose of this study, it suffices to define three concepts.

4.09 Technical efficiency is a question of the possibility to expand some or all outputs or reduce some or all inputs. The typical Farrell measure is the one indicated in Figure 4-1, namely

$$E_i^A = \min\{E \mid (Ex_i, y_i) \in T\}$$

= minimal common fraction of all inputs that suffices to produce the given output.

4.10 When there is only one input, namely costs c_i,, E_i become the fraction of costs that is needed to produce the given output y_i in the given technology. We call this the cost efficiency, CE

$$CE_i = \min\{E \mid (Ec_i, y_i) \in T\} = \text{Minimal costs / Actual costs}$$

4.11 The relationship between costs and inputs are given by $c_i = wx_i$, where w is a vector of factor prices. We see therefore that cost efficiency not only evaluates if given factors are used in the most efficient way, technical efficiency, but also if the mix of factors are optimal given the relative prices

and the technological possibilities to substitute between them, so-called allocative efficiency. For example, CE_i = 0.9 means that it is possible to save 10% of the actual costs.

4.12 A third efficiency concept of direct relevance to the present task is that of sub-vector efficiency. The idea is that some input factors may be controllable but others not (in the given time horizon). The fact that other factors or costs elements cannot be controlled does not mean that they can be ignored since they may interact with the controllable costs. If the (non-controllable) assets are of good quality, for example, this may lead to lower operating costs. To cope with such interdependencies without presuming that everything can be changed, one can use the sub-vector efficiency. Letting x_i^D be the controllable (discretionary) inputs and the x_i^F the non-controllable (fixed) inputs, sub-vector efficiency becomes

$$E_i^{AS} = \min\{E \mid ((Ex_i^D, x_i^F), y_i) \in T\}$$

= minimal common fraction of all controllable inputs that together with the non-controllable inputs suffices to produce the given outputs

4.13 The interaction between controllable and non-controllable inputs (or costs) has implications for regulation. It means for example that a revenue cap ideally should be fixed in view of the capital costs allowed.

4.14 The three efficiency concepts are illustrated in Figure 4-2 below. TE (technical efficiency) corresponds to C/D, CE (cost efficiency) corresponds to B/D and if x^a is assumed to be non-discretionary, the sub-vector efficiency E^S is A/D.

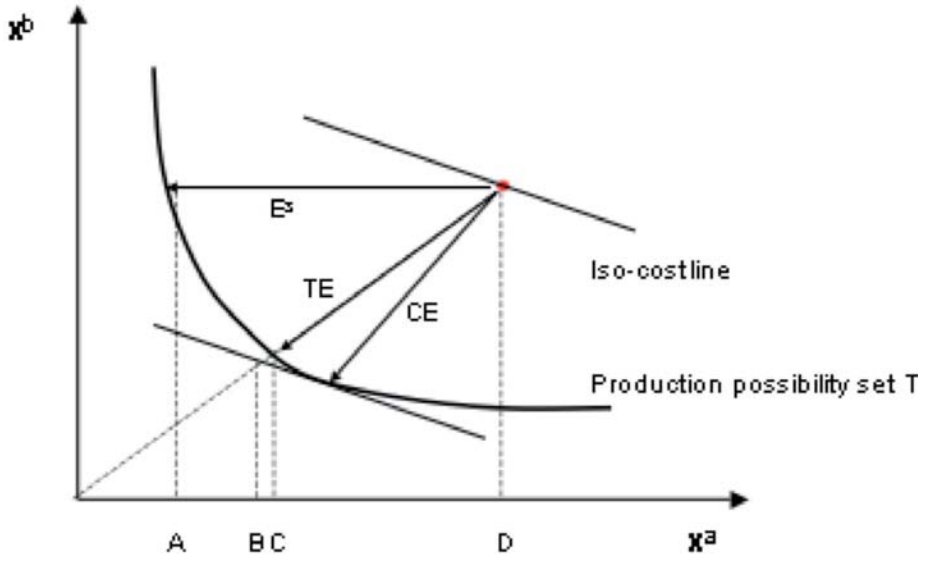


Figure 4-2 Efficiency concepts

Incumbent inefficiency and frontier shift

4.15 The efficiency measures above allow us to measure the incumbent inefficiency, i.e. the excess usage of resources in a given period, of a TSO. In the next stage of the project, we shall engage in dynamic analyses and measure also the technological progress (or regress) of the industry. This corresponds to so-called frontier shifts. They are important for example to determine reasonable dynamic trajectory in regulatory contexts. This is illustrated in Figure 4-3 below.

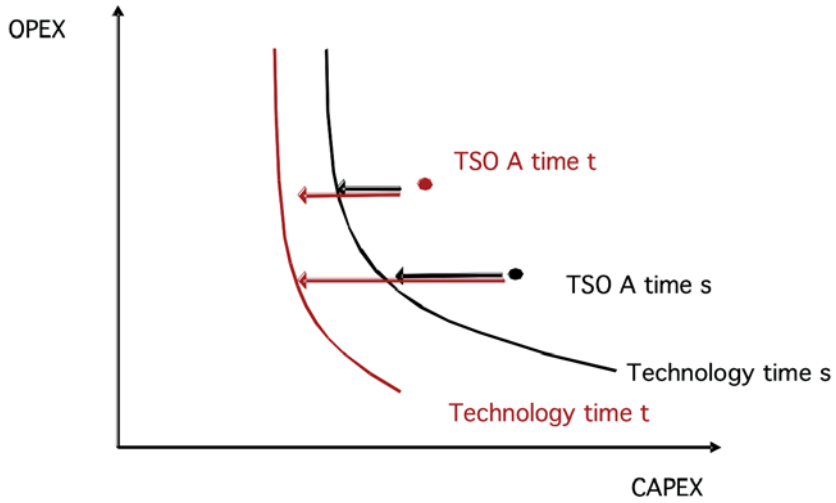


Figure 4-3 Incumbent inefficiency and frontier shifts

4.3 Technology and cost estimation

4.16 Econometrics has provided a portfolio of techniques to estimate the cost models for networks, illustrated in Table 4-1 below. Depending on the assumption regarding the data generating process we divide the techniques in *deterministic* and *stochastic*, and further depending on the functional form into *parametric* and *non-parametric* techniques.

Table 4-1 Model taxonomy

	Deterministic	Stochastic
Parametric	Corrected Ordinary Least Square (COLS) Greene (1997), Lovell (1993), Aigner and Chu (1968)	Stochastic Frontier Analysis (SFA) Aigner, Lovel and Schmidt (1977), Batesee and Coelli (1992), Coelli, Rao and Battesee (1998)
Non-Parametric	Data Envelopment Analysis (DEA) Charnes, Cooper and Rhodes (1978), Deprins, Simar and Tulkens (1984)	Stochastic Data Envelopment Analysis (SDEA) Land, Lovell and Thore (1993), Olesen and Petersen (1995)

4.17 Corrected ordinary least square (COLS) corresponds to estimating an ordinary regression model and then making a parallel shift to make all units be above the minimal cost line. Stochastic Frontier Analysis (SFA) on the other hand recognizes that some of the variation will be noise and only shift the line – in case of a linear mean structure – part of the way towards the COLS line. Data Envelopment Analysis (DEA) estimates the technology using the so-called minimal extrapolation principle. It finds the smallest production set (i.e. the set over the cost curve) containing data and satisfying a minimum of production economic regularities. Like COLS, it is located below all cost-output points, but the functional form is more flexible and the model therefore adapts closer to the data. Finally, Stochastic DEA (SDEA) combines the flexible structure with a realization, that some of the variations may be noisy and only requires most of the points to be enveloped.

4.18 A fundamental difference from a general methodological perspective and from regulatory viewpoint is the relative importance of flexibility in the mean structure vs. precision in the noise separation. This means that there are basically two risks for error that cannot be overcome simultaneously. These are 1) *risk of specification error*, and 2) *risk of data error*.

Specification error

4.19 The inability of the model to reflect and respect the real characteristics of the industry is related to the specification error. Avoiding the risk of specification error requires a flexible model in the wide sense. This means that the shape of the model (or its mean structure to use statistical terms) is able to adapt to data instead of relying excessively on arbitrary assumptions. The non-parametric models are by nature superior in terms of flexibility.

Data error

4.20 The inability to cope with noisy data is called data error. A robust estimation method gives results that are not too sensitive to random variations in data. This is particularly important in yardstick regulation with individual targets – and less important in industry wide motivation and coordination studies. The stochastic models are particularly useful in this respect.

4.21 It is worthwhile to observe that the two properties may to some extent substitute each other. That is, the flexible structure allowed by non-parametric deterministic approaches like DEA may compensate for the fact that DEA does not allow for noise and therefore assigns any deviation from the estimated functional relationship to the inefficiency terms. Likewise, the explicit inclusion of noise or unexplained variation in the data in SFA may to some extent compensate for the fact that the structural relationships are fixed a priori, i.e. the noise terms may not only be interpreted as a data problem but also as a problem in picking the right structural relationship. As an illustration of this, Agrell and Bogetoft(2007) in an analyses of data from several hundred DSOs found that the SFA efficiencies are often larger than the DEA efficiencies as long as the model is somewhat ill-specified, i.e. the inputs and outputs are badly chosen. The reason is that SFA in this case assigns the variations to the noise term while DEA assigns everything to the efficiency term. As the model is extended to include more relevant inputs and outputs, the two methods have been found to produce quite comparable results for sufficiently large datasets.

4.4 Non-parametric models (DEA)

4.22 The basic DEA (Data Envelopment Analysis) formulation for a unit 0 in a set ! of *p* comparators using a process model with *m* inputs and *n* outputs would be

$$
\begin{aligned}
& D_o^{DEA}(X,Y,\Omega,r) = \min \varphi \\
& s.t. \\
& \sum_{k\in\Omega} x^k \lambda_k - x^0 \varphi \le 0 \\
& \sum_{k\in\Omega} y^k \lambda_k - y^0 \ge 0 \\
& \lambda_k \in \Lambda(r), \qquad k \in \Omega
\end{aligned}
$$

where ! denotes the reference set of comparators (i.e. all units but 0 if super-efficiency, otherwise all units), *r* is a short hand for the assumption about returns-to-scale that we make (possible values are crs, vrs, nirs, drs, etc as indicated in Table 4-2 below), 0 is the unit under study, φ is the

radial efficiency score and X and Y are ($m \times p$) and ($n \times p$) matrices for the input and outputs, respectively.

Reference set

4.23 The reference set ! may include all p observations to determine a frontier that includes the unit under evaluation {0}. An additional possibility is to extend the reference set with constructed observations $!_c$ from e.g. engineering norm models, $!' = ! + !_c$. In this manner, an otherwise sparse dataset can still be used for non-parametric incentive provision. In case the reference set includes time series data, care should be taken to correct the economic measures for price changes during the period.

Returns to scale

4.24 One of the few *a priori* assumptions of the non-parametric models includes the returns to scale for the technology. The literature lists the specifications constant returns to scale (crs), non-increasing returns to scale (nirs), non-decreasing returns to scale (ndrs), variable returns to scale (vrs), free replicability hull (frh) and free disposability hull (fdh). Table 4-2 presents a list of the most used assumptions along with their technical inclusion as one or two constraints in the DEA problem above.

Table 4-2 Returns-to-scale assumptions in DEA-models with some references.

Returns to scale	*r*	Set (constraints) L (r)	Reference
constant	CRS	$\{\lambda_k \geq 0 : k \in \Omega\}$	Charnes, Cooper and Rhodes (1978)
non-increasing	NIRS	$\left\{\sum_{k\in\Omega} \lambda_k \leq 1, \lambda_k \geq 0 : k \in \Omega\right\}$	Banker, Charnes, and Cooper (1984)
non-decreasing	NDRS	$\left\{\sum_{k\in\Omega} \lambda_k \geq 1, \lambda_k \geq 0 : k \in \Omega\right\}$	E.g., Bogetoft (1996)
variable	VRS	$\left\{\sum_{k\in\Omega} \lambda_k = 1, \lambda_k \geq 0 : k \in \Omega\right\}$	Banker, Charnes, and Cooper (1984)
free replicability	FRH	$\{\lambda_k = N_+ : k \in \Omega\}$	Tulkens (1993)
free disposability	FDH	$\left\{\sum_{k\in\Omega} \lambda_k = 1, \lambda_k = \{0,1\} : k \in \Omega\right\}$	Deprins et al. (1984)

In words, these assumptions to scale can be interpreted as follows :

- Constant Return to Scale (**CRS**) means that we do not believe there to be significant disadvantage of being small or large
- Non-Increasing Return to Scale (**NIRS**), sometimes referred to as Decreasing Return to Scale (DRS), means that there may be disadvantages of being large but no disadvantages of being small
- Non-Decreasing Return to Scale (**NDRS**), sometimes referred to Increasing Return to Scale (IRS), means that there may be disadvantages of being small but no disadvantages of being large
- Variable Return to Scale (**VRS**) means that there are likely disadvantages of being too small and too large.
- Free Disposability Hull (**FDH**) means that we make no ex ante assumptions about the impact on size and that we even do not assume that we can make linear interpolation (convex combinations) between two points
- Free Replicability Hull (**FRH**) is like FDH except that we also assume that we can combine (replicate) individual units, such that we can compare for example a large TSO with the sum of a small and a medium sized TSO.

The assumption we shall mostly rely on in the analyses is that of Non-Decreasing Return to Scale (NDRS). This assumption is conceptually appealing as one can argue that possible diseconomies to scale can be avoided by organizing a TSO as two or more smaller TSOs that operated more or less independently. We could accomplish the same by assuming FDH or FRH, but these methods severely limits the comparability and are therefore most useful for studies with a much larger data set (number of TSOs). Regulators of DSOs have relied on VRS (Norway, 1996-2006, Sweden 2000) and CRS (the Netherlands 2001, UK) and in recent years more and more often NDRS (Germany).

Orientation

4.25 Most applications in incentive regulation concern input-oriented models with an underlying assumption of cost-minimization over a set of endogenous (controllable) inputs. However, the non-parametric model can be adapted to the setting of output maximization (e.g. maximum utilization of a costly infrastructure with sunk capital, such as an interconnector). The corresponding formulation is

$$D_o^{DEA-OUT}(X,Y,\Omega,r) = \max\theta$$
$$s.t.$$
$$\sum_{k\in\Omega} x^k\lambda_k - x^0 \le 0$$
$$\sum_{k\in\Omega} y^k\lambda_k - y^0\theta \ge 0$$
$$\lambda_k \in \Lambda(r), \qquad k\in\Omega$$

where ! denotes the reference set of comparators (i.e. all units but 0 if superefficiency, otherwise all units), *r* is the assumption regarding returns-to-scale (crs, vrs, nirs, etc), 0 is the unit under study, θ is the radial efficiency score and X and Y are ($m \times p$) and ($n \times p$) matrices for the input and outputs, respectively.

4.26 The non-parametric frontiers such as DEA, mostly presented as input-oriented technical or cost-efficiency formulations with national reference sets are popular tools for the implementation of incentive regulation in networks. Among countries relying completely or partially on such tools in 2008 we find for electricity distribution Austria, Belgium, Finland, Germany, Iceland, Norway and Sweden.

4.27 The so-called stochastic DEA approach, SDEA, is a modification of the DEA model that relaxes the side-constraints of the DEA linear programming problem. The idea is that dominance only needs to hold with reasonable probability to make comparisons relevant. The (few) viable SDEA methods require a priori knowledge of the probability distributions of the parameters, and we do not have enough information in this study to justify such assumptions.

4.5 Parametric approaches

4.28 In the parametric SFA approach, the separation of noise and inefficiency is technically done by assuming that the noise is two sided and inefficiency is one sided. Inefficiency makes costs increase and makes production fall short of the best possible, while noise may also lower the observed costs or increase the observed output. In addition to having one- and two sided deviations, the separation of noise and inefficiency is accomplished by making specific assumptions about the nature of the distributions, e.g. normal and half normal.

4.29 In the parametric approach, one also makes specific assumptions about the type of relationship between the inputs and outputs. The so-called functional form may for example be *linear*, *log-linear* or *translog*. We shall return to these assumptions below.

4.30 To be more specific, we may distinguish between three combinations of noise and inefficiency. Namely pure noise models, pure efficiency models

and combined models. In a cost setting, we may assume that costs, x, depend on a series of output driver, y, as well as on a combination of the inefficiency term $u \geq 0$ and the noise term v for each of the operator i

Pure noise (Ordinary least squares (OLS), average cost function):
$x_i = C(y_i) + v_i$

Pure inefficiency (Deterministic frontier):
$x_i = C(y_i) + u_i$

Combined (Stochastic frontiers):
$x_i = C(y_i) + u_i + v_i$

4.31 In the specifications above, $C(y)$ is the minimal cost function. It defines the least expensive way to provide the outputs y. The functional form of $C(y)$ is given, except for some unknown parameter values β, i.e. one uses $C(y,\beta)$. The statistical analysis seeks to estimate the functional relationship, i.e. β, and to estimate the inefficiencies, i.e. u_i.

OLS approaches

4.32 The first of these specifications (OLS) is the specification in classical statistics. It fits a function to the data in such a way that the positive and negative deviations are as small as possible. The standard measure of goodness-of-fit is the sum of squares of deviations, which is why this approach is often referred to simply as the OLS, ordinary least squares approach. Since the OLS approach does not work with the idea of individual inefficiencies, the usage of OLS in regulation is problematic. It can of course be used to identify likely cost drivers and to evaluate structural inefficiencies. Individual inefficiencies, however, are by assumption absent. OLS is normally used as a preparatory step to find cost drivers for variable selection.

COLS approaches

4.33 A simple application of OLS in regulation is via the so-called corrected OLS, COLS. COLS transforms the OLS estimated cost function such that no TSO is able to beat the cost norm but at least one TSO is performing at the COLS cost function. The transformation is typically done via the constant term, i.e. the cost function is shifted vertically down so that all observed cost–service combinations are at or above the corrected function. Methodologically, COLS suffers from the strong a priory assumptions it invokes. It combines the weak aspects of DEA, namely the ignorance of the possible impact of noise, with the weak aspect of the parametric approach, namely the limited functional flexibility.

Stochastic Frontier Analysis

4.34 The stochastic frontier approach was introduced independently by Aigner, Lovell and Smith (1977) and Meuser and Van den Broeck (1977). This section provides a short introduction to the basic characteristics of SFA. A comprehensive introduction to SFA can be found for example in Coelli et al. (1998).

4.35 The key feature of SFA is that it allows for both noise and inefficiency. In a cost function interpretation, it would specify the costs as

$$x_i = C(y_i) + u_i + v_i$$

where the inefficiency u_i is distributed as a half-normal $N_+(0, !_u^2)$ and the noise term v_i is assumed normally distributed $N(0, !_v^2)$.

4.36 Conceptually, it is attractive to allow for the realistic existence of both noise and inefficiency. The drawback of the approach is on the other hand that we need a priori to justify 1) the distribution of the inefficiency terms and 2) the functional form of the frontier.

4.37 The SFA specification is also attractive by allowing the use of classical statistical approaches like maximum likelihood estimation, likelihood ratio testing etc. The only problem here is that the estimation properties are typically only asymptotic and we have only a small dataset in this study. In a practical way, a potential problem is also that the maximization of the likelihood function may be difficult if it is rather flat since it relies on iterative approximations.

4.38 In a SFA approach, we use the data to come up with a best estimate of the underlying costs function C. Compared to DEA, we have less freedom in our choices since we have to decide already at the outset about a possible class of such functions. Given a best estimate of the cost function C, we can determine the noise plus inefficiency by comparing the actual cost and the cost function value. The separation of noise and inefficiency relies on the asymmetry of the joint distribution and if there is large variation across units, i.e. if the residuals are large and we only have few observations of residuals, then this separation may be numerically difficult.

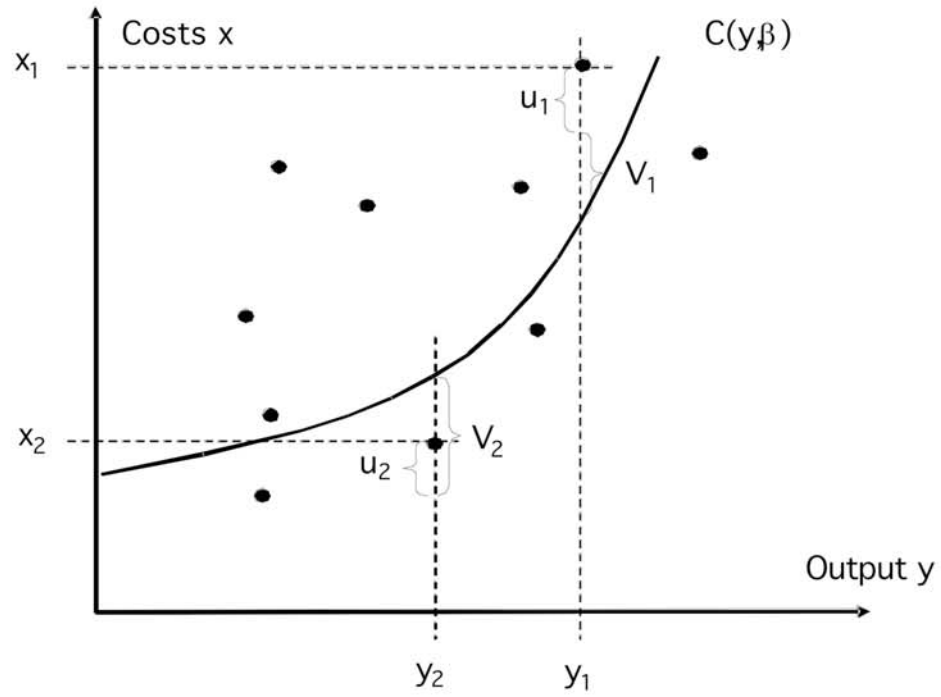


Figure 4-4 Stochastic frontier (both noise v and inefficiency u)

Inefficiency distribution

4.39 SFA requires some a priori assumptions about the distribution of the inefficiency term in order to separate noise and uncertainty. It is hard to give strong arguments for a specific form like the half normal. It is therefore better to start with a more general and more flexible specification and to let the data reveal as closely as possible the correct distribution. We use the accepted general practice to assume that u_i is truncated normal; $N_+ (\mu, \sigma_u^2)$, i.e. a normal distribution centred on μ and next truncated to be above zero.

Functional forms of a cost function

4.40 The second fundamental problem in a parametric frontier approach is to select a functional form for the frontier. The selection of functional form is guided by intuition and data as well as theory. An experienced statistician is usually good at choosing functional forms with possibly data transformations and the sufficient degrees of freedom to provide a reasonable goodness of fit of the data at hand. In addition, theory guides the selection by imposing reasonable properties on the estimated function, e.g. that costs function is homogenous in prices or that output sets are convex. A good general principle is to use the simplest possible representation with the sufficient flexibility to represent data.

4.41 The simplest possible form is the linear one and a good starting point – and even a starting point used in the iterative procedures used to estimate more advanced forms – it is therefore recommended to do a linear regression of cost on the different outputs. Since an additive noise and inefficiency term with fixed variances would correspond to increasing efficiency in the Farrell sense, we shall usually try so-called normed linear models. The idea of this is to estimate (in the case of two cost drivers)

$$x/y_1 = b_0/y_1 + b_1y_1/y_1 + b_2y_2/y_1 + v + u$$

where *x* is cost and *y* are the cost drivers. In the results we shall refer to efficiencies found using this model as **d_sfa_normedlinear_vrs_far**.

4.42 A slightly more complicated specification is the log-linear one being linear in the log of the variables, corresponding to a multiplicative relationship in the original variables, well-known from Cobb-Douglas type functions.

$$\ln x = b_0 + b_1\ln y_1 + b_2\ln y_2 + v + u$$

4.43 In the results we shall refer to these as **d_sfa_loglinear_far** when estimated as SFA cost functions and as **d_colslog_far** when estimated as a corrected least square approximation to the loglinear form, i.e. the case where v = 0 by assumption.

4.44 Linear specifications correspond to first order approximations and the natural next step towards a workable form is to use quadratic approximations, possibly in the log of the variables.

4.45 A second order approximation using log variables gives the so-called translog form. In a cost function specification with *n* outputs and no prices, it pictures the relationship as

$$\ln C_i = b_o + \sum_{j=1}^{n} b_j \ln y_{ij} + \sum_{j=1}^{n}\sum_{k=1}^{n} b_{jk} \ln y_{ij} \ln y_{ik} + u_i + v_i$$

where C_i is the total cost of the i-th unit, y_{ij} is the j-th output quantity of the i-th unit, and the *b*'s are unknown parameters to be estimated.

Summing up

4.46 Figure 4-5 illustrates the approaches. Corrected ordinary least square (COLS) corresponds to estimating an ordinary regression model and then making a parallel shift to make all units be above the minimal cost line. Stochastic Frontier Analysis (SFA) on the other hand recognizes that some of the variation will be noise and only shift the line – in case of a linear mean structure – part of the way towards the COLS line. Data Envelopment Analysis (DEA) estimates the technology using the so-called

minimal extrapolation principle. It finds the smallest production set (i.e. the set over the cost curve) containing data and satisfying a minimum of production economic regularities. Assuming free disposability and convexity, we get the DEA model illustrated in Figure 2-1. Like COLS, it is located below all cost-output points, but the functional form is more flexible and the model therefore adapts closer to the data. Finally, Stochastic DEA (SDEA) combines the flexible structure with a realization, that some of the variations may be noisy and only requires most of the points to be enveloped.

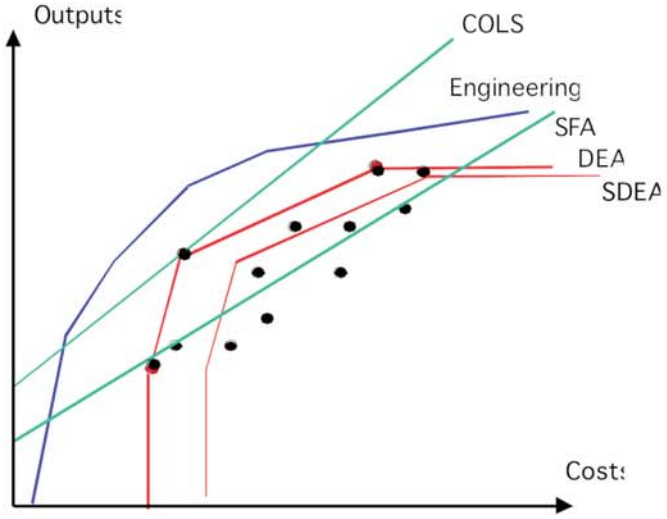


Figure 4-5 Benchmarking methods (example)

In Figure 4-5 we have also sketched a fifth approach, namely the so-called engineering approach. The idea is to capture the theoretical production possibilities by asking for the cheapest new network, the ideal net, engineers could plan and that would be able to provide the services of the existing grid. Needless to say such an approach is very demanding in terms of information as well as computational resources, and from a regulatory perspective is may be a challenge since it is based on hindsight.

From a theoretical perspective, and taking into account informational requirements, the most attractive of these methods are the DEA and SFA approaches.

4.6 Unit cost approach

4.47 The idea of the unit cost approach is very simply. If we consider the set of assets A as the cost drivers, if we assume that the cost of operating one unit of assettype k is w_k, and if we assume that a TSO has an asset base given by the vector **N**, where N_k is the number of assets a, then the norm cost is simply assumed to be

$$NormGrid(.) = \sum_k w_k N_k$$

4.48 The cost norm derived in this way is sometimes referred to as the *Grid Volume*, *SizeOfGrid* or *Norm[alized]Grid NG*.

4.49 Now by comparing the actual costs to such a measure of the size of the grid, we get a cost per grid unit, here called *unit cost*. That is, Unit Cost is cost per grid unit

UC= cost / grid size

4.50 It is comparable in the interpretation to a simple partial measure like cost per [circuit] km of lines for example. The advance of the UC approach however is that by using weights we can aggregate different asset types together such that we do not need to rely on partial thinking.

4.51 Now, given the unit costs, we can proceed to make benchmarking like in the previous sections by comparing the performance of a given TSO to the performance of the TSO with lowest unit costs. That is the benchmark in this approach is the company with lowest unit costs

Benchmark = min {unit costs}

4.52 The efficiency can therefore be calculated as

E = benchmark / unit cost

4.53 This has the same interpretation as the efficiencies described above. A score of 0.8 would for example suggest that it is possible to save 20% of the costs.

4.54 Depending on the interpretation of the weights – e.g. if they are reflecting the total, the operating or the capital cost of one unit of the assets, this approach can be used to derive Totex, Opex and Capex efficiency measure, cf. Agrell and Bogetoft (2006b). That is, we get three measures

$$OpEx\ E^i = \min \{OpEx\ UC^k\} / OpEx\ UC^i$$

$$CapEx\ E^i = \min \{CapEx\ UC^k\} / CapEx\ UC^i$$

$$Total\ E^i = \min \{Total\ UC^k\} / Total\ UC^i$$

4.55 In the chapter with results, they shall be denoted **d_ucopex_far**, **d_uccapex_far** and **d_uc_far**, respectively. We use these names to explicitly link the results to the underlying computer codes used for the calculations. (The somewhat cumbersome names use the _far extension to

reflecting that it is a so-called Farrell measure as in the DEA and SFA programs above, and the d_ initial as a short hand for distance)

4.56 The partial measures for Opex and Capex efficiency provide intuitive interpretations as how efficient a TSO is in its daily operations today and how efficient it has been in its past investments. For this reasons they have some partial appeal and they are still quite developed compared to the usual partial measures since the Size of Grid measure provides an informed aggregate. The ECOM+ method for transmission system benchmarking (Agrell and Bogetoft, 2003c, 2006b) is based on a unit cost logic, since it was developed for small datasets.

4.57 On the other hand, the partial measures ignore the substitution between capital expenditures and operating expenditures.

4.58 So far we have explained the basic idea of the unit cost approach. The implementation of this idea however relies on a series of more specific standardizations of the actual costs and corresponding standardizations of the size of grid measures. Indeed, as explained in details in the Chapter on Parameters, we shall rely on a standardization as illustrated in Figure 4-6 below.

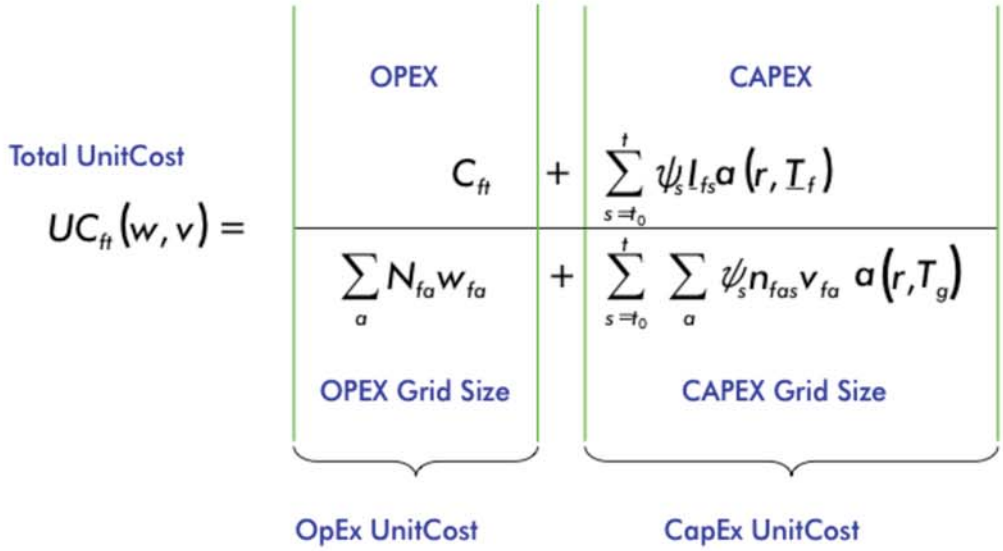


Figure 4-6 Three unit cost measures

UC_{ft}	Unit Cost of firm f at time t
C_{ft}	Total OPEX for firm *f* and time *t*
I_{fs}	Investment budget firm *f* and time *s* after inflation and currency correction)
N_{fa}	Number of assets of type *a* that firm *f* operates at time *t*

n_{fas}	Number of assets of type *a* acquired by firm *f* in period *s*
v_{fa}	Weights (raw) for CAPEX, firm *f* asset a
w_{fa}	Weights (raw) for OPEX, firm *f* asset a
$a(r,T_g)$	Annuity factor for asset with life time T_g and interest rate r
ψ_s	Forgiveness factor used to curtail the evaluation horizon

4.7 Data cleaning, structural corrections and sensitivity analyses

4.59 The cleaning of data is a major effort in any regulatory application of the above methods. Likewise, the post analyses and sensitivity analyses are important to correct for any remaining noise and to evaluate the impact of other assumptions made in the estimations. We will briefly outline some important data cleaning and sensitivity analyses techniques in this section.

Outlier analyses

4.60 *Outlier analysis* consists of screening extreme observations in the model against average performance. Depending on the approach chosen (OLS, DEA, SFA), outliers may have different impact. In DEA, particular emphasis is put on the quality of observations that define best practice. The outlier analysis in DEA can use statistical methods as well as the dual formulation, where marginal substitution ratios can reveal whether an observation is likely to contain errors. In SFA, outliers may distort the estimation of the curvature and increase the magnitude of the idiosyncratic error term, thus increasing average efficiency estimates in the sample. In particular, observations that have a disproportionate impact (influence or leverage) on the sign, size and significance of estimated coefficients are reviewed using a battery of methods that is described below.

4.61 In non-parametric methods, extreme observations are such that dominate a large part of the sample directly or through convex combinations. Usually, if erroneous, they are fairly few and may be detected using direct review of multiplier weights and peeling techniques. The outliers are then systematically reviewed in all input and output dimensions to verify whether the observations are attached with errors in data. The occurrence and impact of outliers in non-parametric settings is mitigated with the enlargement of the sample size. However, in the current project, the outlier detection has prompted analyses of the underlying asset base and

operating conditions to determine the reasons for the qualification as outlier (see below).

4.62 In parametric methods, we are concerned with observations for which the x-value is extremely large, meaning that they have a potential leverage in influencing the shape and slope of the regression and that are off-center in the meaning that they actually exercise their leverage. In Agrell and Bogetoft (2007) we describe four diagnostic functions that can be used in automated outlier analysis in the regression phase: Cook's distance, DFFits, DFBetas and covariance ratios. Due to the size of the sample, we shall nor make use of these methods in this study.

Outlier detection in DEA

4.63 In frontier analysis, the observation included in a reference or evaluation set is called a Decision Making Unit (DMU). A DMU can be an observation of (inputs,outputs) for a firm at a given time (cross section) or at other time periods (panel data), alternatively constructed observations from some activity model (cf art 4.23). Outlier DMU may belong to a different technology by either errors in data, or unobserved quantities or qualities for inputs or outputs. The identification of DMUs to check more carefully has used in particular four approaches.

4.64 One is to identify the number of times a DMU serves as a peer unit for other DMUs, *peer counting*. If a DMU is the peer for an extreme number of units, it is either a very efficient unit – or there may be some mistakes in the reported numbers.

4.65 The other approach is to investigate the impact on average efficiency from unilateral elimination of the DMUs, *efficiency ladders*. If the elimination of one DMU leads to a significant increase in the efficiency of a sufficient number of units, there are again good reasons to check this unit more carefully.

4.66 Thirdly, we have done so-called *shell analysis* where the idea is to study the impact of groups of DMU, like the ones in the first shell, the second shell etc, cf also Agrell and Bogetoft (2002a). As the cost function is peeled this way, one shall check the shells with a significant impact on efficiency while there is less reason to continue the controls when the average efficiency is only improving slightly when a shell is eliminated.

4.67 Finally, we have used super-efficiency calculations to determine units with extreme super-efficiencies that are often associated with outliers, cf. Banker and Chang (2005). Other outlier detection methods designed with particular focus on frontier models have also been considered, for example Wilson (1993).

4.68 The outlier detection used in the final runs follows the German Ordinance for Incentive Regulation and the notion of DEA outliers herein (ARegV, annex 3). The invoked criteria are consistent with the method proposed and used in Agrell and Bogetoft (2007), representing a systematic and useful device to improve the reliability of regulatory benchmarking without resorting to *ad hoc* approaches. The idea is to use a dual screening device to pick out units that are doing extreme as individual observations and that are having an extreme impact on the evaluation of the remaining units. To do so, we use a super efficiency criterion similar to the Banker and Chang(2005) approach, although we let the cut-off level be determined from the empirical distribution of the super efficiency scores. In addition we use a sums-of-squares deviation indicator similar to what is commonly seen in parametric statistics.

4.69 Let I be the set of n TSO in the data set and i be a potential outlier. Also let E (k,I) be the efficiency of k when all TSO are used to estimate the technology and let E (k;I\i) be the efficiency when TSO i does not enter the estimation. We can therefore evaluate the impact on the average efficiency by

$$\sum_{k \in I} (E(k;I \setminus i) - 1))^2 / \sum_{k \in I} (E(k;I) - 1)^2$$

4.70 Large values of this as evaluated in a F (n-1,n-1) distribution, cf. Banker (1996), will be an indication that i is an outlier.

4.71 Using also the super-efficiency criteria of the Ordinance (ARegV), we shall classify an entity i as an outlier to be eliminated if

$$E(i;I\setminus i) > q(0.75) + 1.5 * (q(0.75) - q(0.25))$$

where $q(\alpha)$ is the α-fractile of the distribution of super-efficiencies, such that e.g. q (0.75) is the super-efficiency value that 75% has a value below. Hence, this criterion indicates if there are units that are having much higher super-efficiencies than the other units. If the distribution is uniform between 0 and 1 in a large sample, for example, all other units are evenly distributed between 0 and 1, a candidate unit must have super efficiency above 0.75+1.5*(0.75-0.25)=1.5 to be an outlier.

4.72 We shall report the DEA-ndrs results both with and without the possible outliers according to this definition. We shall denote these **d_dea_far_ndrs** and **d_dea_far_ndrs_ex_out** respectively.

Bias correction

4.73 DEA models provide cautious estimates of the saving potentials and cost inefficiencies. This is one of the attractive features of DEA and is part of the

theoretical foundation for the optimality of DEA based yardstick competition, cf. Bogetoft (1997,2000). If the model structure and the variables are chosen correctly, it means that no-one will be required to produce at costs that are below the truly minimal ones. In the terminology of incentive theory, the outcome is *individually rational*.

4.74 The backside of the cautiousness is that the cost efficiency is biased upwards. On average, the units will look more efficient than they probably are. More precisely, if we know the underlying true cost function they would likely look less efficient. This is the difference between absolute efficiency measured against the true minimal cost norm and relative efficiency as measured against the best practises of the existing sample.

4.75 To evaluate the robustness of our efficiency scores it can therefore be interesting to compare the relative efficiencies with the absolute ones (the bias corrected ones) – and the confidence interval for these. The wider is the confidence interval the more uncertain we are about absolute efficiency.

4.76 Recent theoretical developments have taught us how to correct for this bias, namely via boot-strapping. In consequence, we can – following the literature initiated by Simar and Wilson (2000) – determine bias corrected efficiency scores, i.e. scores that are not biased. Moreover, using bootstrapping, we can determine confidence intervals around the bias corrected efficiencies. We shall rely on these advances in the empirical analysis. The procedure involves the simulation of for example 2000 different versions of a model with variable and properties fixed but with the inefficiencies drawn from an efficiency distribution determined by a so-called kernel estimation of the empirical efficiency distribution (i.e. non-naive bootstrapping).

4.77 In the full results below we shall report the bias corrected efficiency scores and the corresponding 95% confidence intervals as well. They shall be denoted **d_dea_far_ndrs_biascorr**, **d_dea_far_ndrs_biascorr_c1**, and **d_dea_far_ndrs_biascorr_c2**, respectively where the two last define the lower and upper bound of the confidence interval.

Structural corrections

4.78 The relative performance evaluation of the TSO shall ideally be corrected for difference in the structural conditions. Thus, a TSO forced to live with the difficulties of special climate, topology, particularly dispersed costumers etc shall not be compared directly with TSO without these challenges. There are several ways to correct for such differences and to test their importance.

4.79 In a DEA framework, *ordinal structural variables* can be used to group the TSO and to only compare a TSO against TSOs working under less favorable conditions. If the structural variables are interval scaled, we can instead include them as pseudo non-controllable inputs or outputs.

4.80 Another and more common approach is to rely on *second stage analyses*. In a second stage analysis, the efficiency scores are regressed against the structural variable to determine the general impact of these. Next the efficiencies are corrected for the impact of these variables using the regression model. Often, an OLS estimation is used, but if one analyzes ordinary efficiencies as opposed to superefficiencies, one should ideally take into account the truncated nature of the dependent variable, the efficiency, i.e. one should use a truncated regression à la Simar and Wilson (2004) or a TOBIT regression following Tobin (1958).

4.81 In an SFA framework, the correction for structural variables can be handled as an integral part of the *maximum likelihood estimation* by parameterizing the inefficiency distribution with such variables, cf. Battese and Coelli (1992). This approach seems to be superior to second-stage analyses, cf. Coelli and Perelman (1999).

4.82 In some case, we are not interested to correct the efficiency scores for the structural variables but we are interested to know if the model is biased against one type of TSO rather than another, e.g. bias in asset age due to nominal capital values. In such cases, one can – in addition to the second stage regressions – make non-parametric tests – like classical Mann-Witney and Kruskal and Wallis tests.

4.8 Dynamic productivity and efficiency assessment

4.83 In the previous sections we concentrated on the static performance of the TSOs. We considered different conceptual models of the relationship between costs and services provided by the TSOs, and for each of these models we used several estimation methods to derive calibrated models based on actual data. In each situation, we could then estimate the static efficiency of the TSOs, i.e. the extent to which OPEX and Capex could have been reduced in a given year.

4.84 Over time, however, both the behaviour of an individual TSO and the nature of the technology are likely to change. These dynamic changes are of considerable interest to regulators and TSOs alike.

4.85 A TSO may reduce its resource usage from one year to another. To understand and decompose this improvement, however, the improvement must be compared to the changes undertaken by other TSOs. If a TSO improves but does so at a slower pace that other TSOs, it effectively is

falling behind. Likewise, if a TSO is increasing its cost it may look like increased inefficiency but if other TSOs are increasing costs faster, it may really reflect that the TSO in question is improving but that the technology is regressing.

4.86 In the scientific literature *productivity* refers to changes over time. If outputs change more than inputs, productivity improves. We shall now discuss how such changes can be measured and decomposed into technological changes and individual changes relative to the technology.

4.9 Fisher indexes

4.87 If prices or priority weights are available for both the resources used and the services produced, one can use classical measures of total factor productivity, TFP.

4.88 Productivity is in general defined as the ratio of changes in outputs to changes in inputs. The Total Factor Productivity is an extension to the case of multiple inputs and outputs:

$$TFP = \frac{\Delta Y}{\Delta X}$$

4.89 where ΔY is the proportional change in output quantity and ΔX is the corresponding change in input quanta. The multiple dimensions are weighted according to some set of weights, the most popular being the Fisher ideal index (Diewert, 2004) that uses (exogenously given) prices. The total factor productivity growth from a base year 0 to a later year t is obtained as:

$$TFP^t = \frac{\sqrt{\left(\sum_i p_i^0 y_i^t / \sum_k p_k^0 y_k^0\right)\left(\sum_i p_i^t y_i^t / \sum_k p_k^t y_k^0\right)}}{\sqrt{\left(\sum_i w_i^0 x_i^t / \sum_k w_k^0 x_k^0\right)\left(\sum_i w_i^t x_i^t / \sum_k w_k^t x_k^0\right)}}$$

4.90 where p_i^0 is the price for output i in the base period 0, p_i^t is the price of output i in period $t = \{1,..,T\}$, y_i^0 and y_i^t are the output quantities of item i in periods 0 and t, respectively, w_i^0 and w_i^t are the input prices for input i in periods 0 and t, respectively, and x_i^0 and x_i^t are the quantities of input i in periods 0 and t, respectively. The summation indexes i and k are covering the same range of all inputs and outputs, respectively.

4.91 An obvious challenge with this TFP method is to obtain an a priori set of valid market prices for all outputs, i.e. prices that should reflect a profit maximizing behaviour. In the case of infrastructure regulation, these prices

are normally endogenous from the regulation and the objectives may be mixed or unclear.

4.10 Malmquist methods

4.92 The standard approach to dynamic evaluations when we do not have complete prices or priority weights on both the resource and the service sides is to use so-called *Malmquist index*.

4.93 The Malmquist index uses information about the technology and changes herein as a substitute for fixed prices. Hence, to apply the Malmquist approach, we need to estimate the technology like in the first interim report R1.

4.94 The Malmquist index measures the change from one period to the next by the geometric mean of the performance change relative to the past and present technology. Specifically, let $E_i(s,t)$ be a measure of the performance of TSO_i in period s against the technology in period t. Now, TSO_i '*s* improvement from period s to period t can be evaluated by the Malmquist index $M_i(s,t)$ given by

$$M_i(s,t) = \sqrt{\frac{E_i(t,s)}{E_i(s,s)}\frac{E_i(t,t)}{E_i(s,t)}}$$

4.95 The intuition of this index runs as follows. We seek to compare the performance in period s to period t. The base technology can be either s or t technology, so we take geometric mean. Improvements make nominator larger than denominator. Hence, $M > 1$ corresponds to progress and for example $M = 1.2$ would suggest a 20% improvement from period s to t, i.e. a fall in the resource usage of 20%.

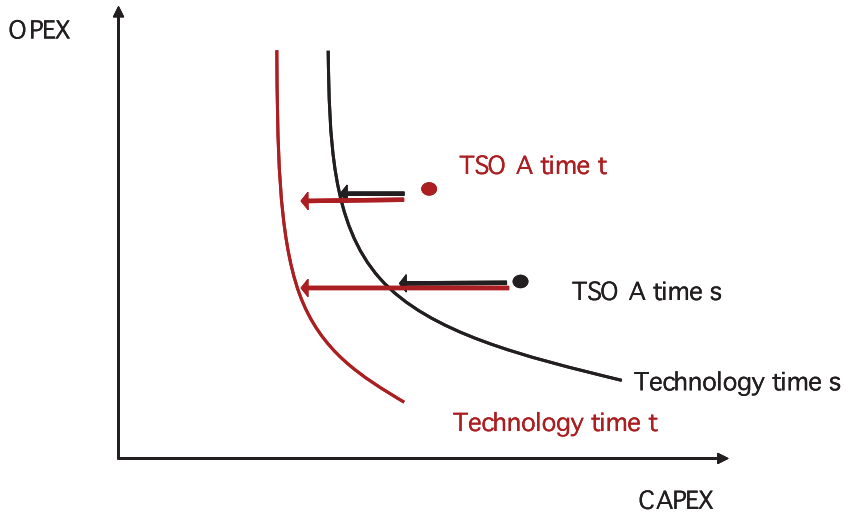


Figure 4-7 Dynamics

4.96 The change in performance captured by the Malmquist index may be due to two, possibly enforcing and possibly counteracting factors. One is the technical change, TC, that measures the shift in the production frontiers corresponding to a technological progress or regress. The other is the efficiency change EC which measures the catch-up relative to a fixed frontier. This decomposition is developed by a simple rewrite of the Malmquist formula above given by

$$M_i(s,t) = \sqrt{\frac{E_i(t,s)}{E_i(t,t)}\frac{E_i(s,s)}{E_i(s,t)}} \cdot \frac{E_i(t,t)}{E_i(s,s)} = TC_i(s,t)EC_i(s,t)$$

4.97 Again, the interpretation is that values of TC above 1 represent technological progress – more can be produced using less resources – while values of EC above 1 represents catching-up, i.e. less waste compared to the best practice of the year.

4.98 The Malmquist measure and its decompositions are useful to capture the dynamic developments from one period to the next. It is applicable for general multiple input multiple output production processes.

4.99 Over several periods, one should be careful in the interpretation. One cannot simply accumulate the changes since the index does not satisfy the so-called circular test, i.e. we may not have M (1,2) × M (2,3) = M (1,3) unless the technical change is so-called Hicks-neutral. This drawback is shared by many other indices and can be remedied for example by using a fixed base technology. This, however, is beyond the scope of this report.

4.11 Summary and implementation

4.100 TFP in one version or the other is frequently used in incentive regulation in the US and in price-cap regulation in the Anglo-Saxon tradition (e.g. New Zealand in Lawrence and Diewert, 2006). For an excellent introduction to TFP estimations in regulation, see Coelli, Estache, Perelman and Trujillo (2003), further examples of studies are presented in Coelli and Lawrence (2006).

4.101 Frontier shifts in an industry are the result of many factors. It is possible to "push the frontier" by developing new organization forms, incentive schemes, operational procedures etc. Likewise it is possible to push the frontier by introducing new equipment or by combining known technologies in new ways.

4.102 The frontier shift derived from such changes in the soft- and hardware of an industry can be expected to be less dependent on the specific unit being analyzed. Frontier shift is a matter of change over time, and even if the level of efficiency may depend on many local factors, the change in level is likely to be rather uniform. In turn, this suggests that one can derive interesting frontier shifts from several data sets and that the usual problem of structural comparability (validation of task base, asset base standards etc) is less important.

4.103 On the other hand, the evaluation of changes is complicated by increased variance. The variance of an estimate of a difference or ratio may be significantly larger than the variance of its components (depending of course of the correlation between the two). This means that more years and more data sets are important in the estimation of frontier shifts.

4.104 The static efficiency methods above and the dynamic productivity measures discussed in this subsection allow us to measure both the *incumbent inefficiency*, i.e. the excess usage of resources in a given period, of a TSO, and the *technological progress* (or regress) of the industry, i.e. a reasonable dynamic trajectory. This is illustrated in Figure 4-8 below.

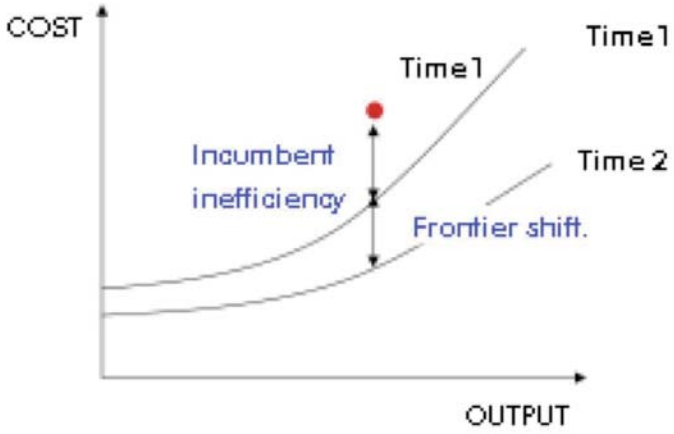


Figure 4-8 Incumbent inefficiency and frontier shifts

Implementation of results

4.105 The implementation of a cost efficiency target for incumbent (static) inefficiency in network regulation requires a careful analysis of the current and past regulation regime, the information available for the operator and its particular financial situation. Current regulation determines the scope of activities under incentive regulation, i.e. the controllability assumption under a given legislation, and the length of the regulatory contract. If past regulation differs with respect to specific costs and investments to the extent that the investors' confidence may be lowered, consideration must be made to adjust for items (cost or assets) as to maintain regulatory commitment. The previous points determine normally the exact scope of the benchmarked costs and the duration for catch-up of any detected incumbent inefficiency. If the scope differs from the functional decomposition in the current report (and not only in the costs approved), specific runs have to be made as to enable a correct estimate. Likewise, if the reference set for the evaluated unit differs by law or other analysis, the frontier above has to be reestimated. However, the length of the regulatory period and the information available may also intervene when selecting the optimal model to implement. As argued above, limited information about relative performance and short regulatory periods are arguments to implement a cautious approach in a benchmarking as e3GRID. The risk of infeasible cost targets would in such setting jeopardize the credibility of the regulatory instrument without bringing substantial benefits for consumers (the short period), nor offer the firm the necessary time to internalize average effects. Thus, the main results forwarded in this study are the DEA/NDRS results excluding outliers. More extensive information about the performance in combination with long regulation periods, on the other hand, speak in favour of using less cautious estimates as the firm will benefit both from short-term information rents

and the time to internalize average effects. In this situation, a regulator may use information from the biascorrected scores, either mean results or points in the confidence interval. Finally, a regulator promoting structural change may which not to award credit for less than optimal scale, which here would lead to the adoption of CRS results in either the standard or bias-corrected DEA model.

4.106 A common use of the dynamic results (Malmquist, catch-up and frontier shift) is to use the frontier shift estimate as a component in the common efficiency requirement (X) for all operators and to use a fraction of the (static) incumbent inefficiency estimate in potential individual efficiency requirement (X_i) in a revenue or price-cap regime. The fraction of incumbent inefficiency to reduce during a given regulatory period may be related to specific information about the expected improvement potential of the operator, or related to the average catch-up speed revealed by similar operators in the study.

5. Parameter definitions

5.1 General

5.01 We define a parameter as a constant used in the calculations of a final or intermediary result in the benchmarking, as opposed to a variable or indicator that is selected through the model specification phase below. Below the parameters used in the study are presented and defined for the final results. Note that the values of parameters have no normative value and should not be interpreted as being direct indicators of the cost or time for the specific dimension they refer to, since they are derived here for the purpose of comparability. The actual parameter values used in the final run are marked in grey fields for clarity.

5.2 Interest rate

5.02 The investment streams are transformed into annuities, using an interest rate and an asset class specific lifetime. The interest rate can be decomposed further into a risk-free rate that depends solely on the development of the market and an industry specific premium that depends on the enterprise. It goes beyond the scope of this study to determine an industry-specific premium, as this involves very careful analysis of the investment risk and financial leverage, regulatory trajectory and other factors that are not necessarily common among the operators in the study. NRAs have commissioned a number of such studies focusing at electricity transmission or distribution, cf. Wright et al. (2006) for OFGEM (UK) and Frontier Economics (2005, 2008) for EK (UK). The objective of this parameter is to provide a common denominator for part of this component, the risk-free rate, for the common benchmarking. Extensive sensitivity analysis (cf. subsection 9.2) coupled with individual analyses for NRAs using their exact parameters allow the assessment of the sensitivity with respect to the second component.

5.03 Wright, Mason, Miles (2003) identify (amongst others) some caveats in the estimation of risk-free premium.

1) *The highly integrated nature of capital markets should be taken into account. They present evidences in favor for treating "common components of the cost of equity as being determined in world markets"*

2) *They point out that the investor's expectation is not measurable. By approximation with historic data there exists a risk that arbitrary fluctuations are picked up – they recommend therefore a long enough series of observations.*

5.04 Frontier Economics (2008) expands on the latter and considers the main issues for the risk free proxy

1) *The appropriate maturity of debt; and*
2) *Whether to use current rates or long-term averages.*

5.05 The first point is critical in the context of this European benchmark exercise. After the EU enlargement in January 2004 all participating countries of the benchmark, except Norway and Iceland, are part of the Internal Market. But stepwise integration into the financial system took already place before 2004. Although there are still some small differences in the interest rates, we can observe a convergence. Eurostat (http://ec.europa.eu/eurostat) provides aggregated financial information with respect to different time horizons1. The second point draws on the time horizon of the proxy and the length of the time window that should be taken into consideration.

5.06 A longer maturity of debt – so a bond with a longer remaining duration – bears a higher risk than a shorter one, because e.g. it is longer exposed to the risk of inflation. Therefore a short-term bond mimics better the risk-free rate. This advantage might be offset by the exposure to short-term fluctuations in the market.

5.07 As proxy for the risk-free rate regulators use often 10 years governmental bonds (e.g. Bundesnetzagentur, Germany; EK, The Netherlands).

5.08 The choice of the rate vs long-term averages faces similar problems as the choice for the maturity of debt. The longer the average, the less volatile are the calculated values.

5.09 Compared a ten-year and a five-year average of 10-year government EUR-bond yields leads to 4.86% and 4.09% respectively. Frontier (2008) concludes on a risk-free rate between 3.9% and 4.1%, the debt premium is estimated to 0.8% and inflation to 1.25%, leading to a window for pre-tax cost of capital of 4.7% to 6.7% for NL networks in EUR. Wright et al. (2006) recommend real cost of equity estimates between 4.5% and 6.25% combined with a real cost of debt window of 3.5% to 4.75% for the UK regulated business in GBP. Since the real interest rate here is applied equally across all TSO in order to standardize Capex annuities, there is no reason to adjust it particularly to any country, inflation rate or assumption about the capital structure. Moreover, the interest rate is not intended for normative use to prescribe the cost of debt in the past or in the future. Fortunately, the sensitivity of the results with respect to the common interest rate, reported in (cf. subsection 9.2), is low, making the choice somewhat arbitrary in a range. Given that real interest rates have fallen lately and the intersection with the lower estimates for real cost of capital estimates, we chose 4.86% as the real reference rate.

[1] From January 1999 the weightings for Euro area are based on each country's nominal stock of government bonds of around.

5.10 The real interest rate for Capex is set to 4.86%.

5.3 Asset lifetimes

5.11 The actual investment streams I_{ts} – after correction for currency and inflation – are annualized using a standard annuity factor $\alpha(r,T)$, where r is the real interest rate above. The parameters r and T are both subject to sensitivity analysis.

$$\alpha(r,T) = \frac{r}{1-(1+r)^{-T}}$$

5.12 The accounting life of the grid assets varies in the group depending on regulatory and fiscal rules, time and ownership form. Since the benchmarking is based on a standardized measure that is to reflect the techno-economic life of the assets, it was decided to harmonize the life time per asset type. Since the use of the assets is reflected in their prevalence in the asset database, the standardized lifetime is based on some average numbers for the techno-economic lifetime. Conservative bounds for the asset ages for the reported assets in e³GRID are presented in Figure 5-1 below, where the censored distribution for each operator at 1964 has been replaced with a dummy at an arbitrary 50 year age. The mean age is indicated with a red number, the median age by a blue number below the quintile boxplot, where the edges of the boxes are drawn at 5% and 95%, respectively, and observations beyond the interval are denoted by unfilled circles. Since other analyses have shown stable reinvestment rate over time in real terms, a simple assumption would be that the current asset age represents half the economic life of the asset. With some rounding and grouping with respect to certain elements (transformers, compensating devices and series compensation) the values in Table 5-1 are obtained.

5.13 The life times are within a feasible range and lower than some suggested internationally. A rate review for a transmission operator in Australia was recommended to use 70 years for steel tower transmission lines and 45 years for substations (PB Power, 1999). However, for some asset types (control centers and HVDC assets), the average age may be subject to adjustments for certain operators, this is analogous to an adjustment of the relative asset weight, cf. sensitivity analysis of the parameters (subsection 9.5).

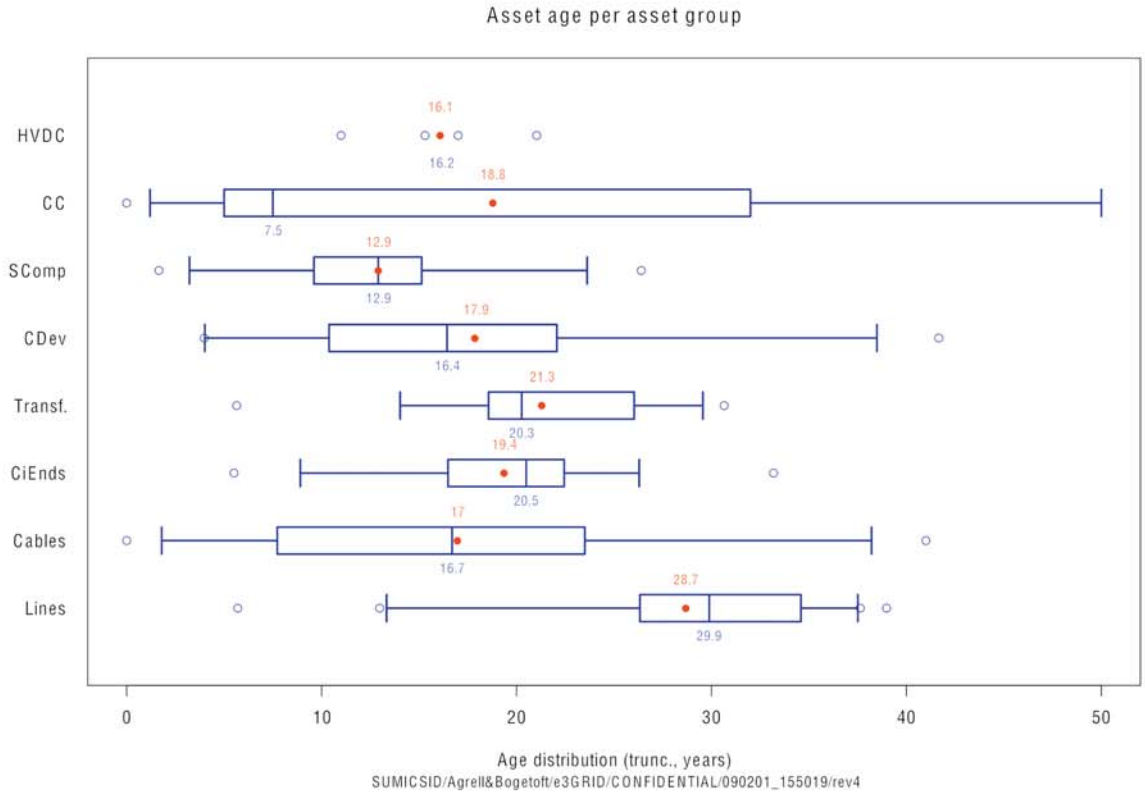


Figure 5-1 Average asset age per asset type (truncated distributions), red = mean, blue = median.

Table 5-1 Life times T_g used in e³GRID.

Group g	Contents	Lifetimes (yrs)
1	Lines	60
2	Cables	50
3	Circuit ends	45
4	Transformers	40
5	Compensating devices	40
6	Series compensations	40
7	Control centers	30
8	Other assets (HVDC)	30

5.14 The lifetime in each of eight asset group is set to a technical life between 60 years (lines) and 30 years (control centers and HVDC converters).

5.4 Investment lifetime

5.15 The uniform standardized lifetime for the investments used in interim reports creates a minor bias for operators with particular investment profiles over time. To improve the precision of the Capex measure, a more correct estimation has been used in the final run. The average lifetime of any investment basket for any operator, used in the annuity calculations for standardized Capex, is set to the weighted average life of their investments undertaken the same year.

$$\tau_{it} = \sum_k \left\{ \frac{T_k w_k x_{ikt}}{\sum_k w_k x_{ikt}} \right\}$$

where τ_{it} the average weighted lifetime for assets of TSO *i* in year *t*, assets of type *k* invested by TSO *i* in year *t*, normalized Capex weight for asset-type *k*, T_k is the standardized asset lifetime for assettype *k* (cf art 5.13 above). The annuity factor used a_{it} is defined from τ_{it} and the real interest rate *r* (cf 5.01) as:

$$\alpha_{it} = \frac{r}{1-(1+r)^{-\tau_{it}}}$$

5.16 Lifetime for investments is set to the weighted average lifetime for actual investments per TSO and year.

5.5 Evaluation horizon

5.17 No variation has been made to the evaluation horizon for assets and investments, set to the full span of data from 1964/1965 – 2006. In accordance with the project plan, the static efficiency refers exclusively to 2006 with regards to operating costs, capital expenditure and total expenditure. Dynamic efficiency development and productivity growth are investigated in aggregate to determine frontier shift and catch-up performance. Individual efficiency development is facilitated by detailed cost comparisons included in the individual confidential summaries. Since the data is not balanced between operators, panel data has been used only for validation in the variable selection phase.

5.18 Static efficiency is estimated only for 2006. All assets and investments are used from 1964/65.

5.6 Reference year

5.19 All monetary amounts are translated to EUR in 2006 value.

5.7 Inflation adjustment

5.20 The value of the past investments relative to the reference year is calculated using inflation indexes. Ideally, a sector-relevant index would capture both differences in the cost development of capital goods and services, but also the possible quality differences in standard investments. However, such index does not exist to our best knowledge. Several indexes have been collected from EUROSTAT, OECD, BLS and national statistical bureaus, but the only generally defined index for the horizon for all 22 participating grids is the simple Consumer Price Index (CPI). As illustrated in Figure 5-2 the use of CPI compared to Producer Price Index (PPI) is not neutral to the results for the Capex component of the standardized total cost. Sector-specific indexes only exist for a handful of countries and require additional assumptions to be used for countries outside of their definition. To create a comparable base, it was decided to use only CPI. The use of CPI has some advantages also with respect to the cost development of staff costs and is moreover a common inflation adjustment in revenue-cap formulas.

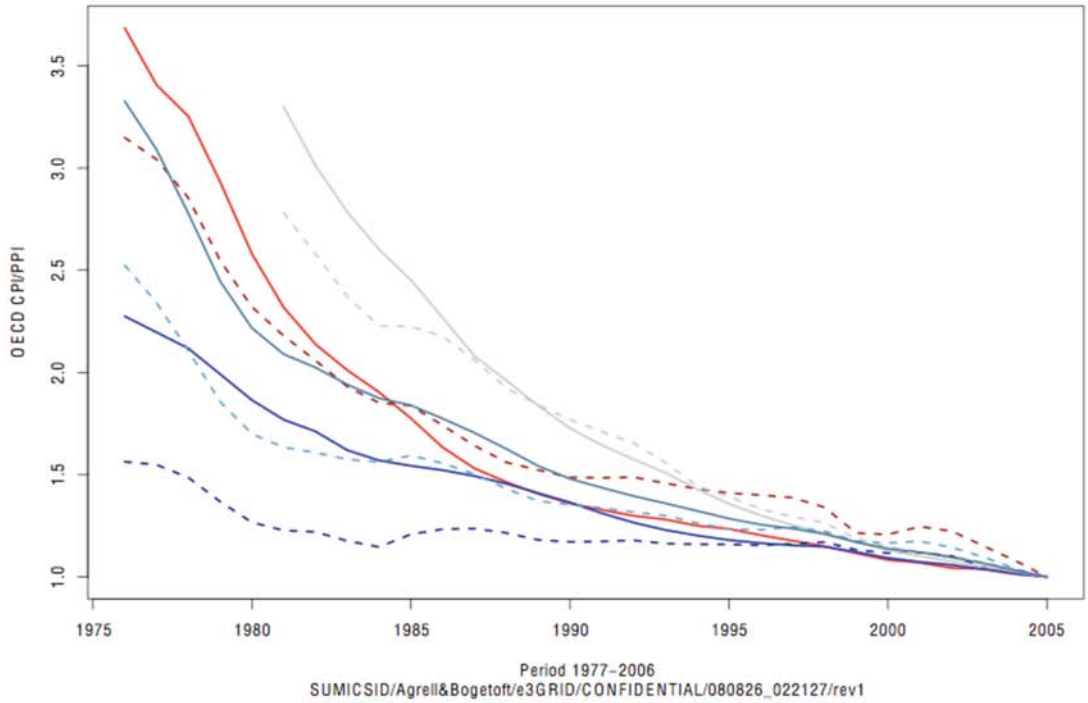


Figure 5-2 Inflation series for OECD (grey), US (skyblue), Norway (red), Austria (dark blue), CPI (solid) and PPI (dashed). OECD, 2008

5.21 Inflation is adjusted using CPI data for each country, collected through OECD.

5.8 Salary cost adjustments

5.22 Correction has been made for national manpower compensation costs through the use of a general and a sector-specific index. Indexes from BLS for production and manufacturing workers in a subset of the countries involved were also reviewed, see the e³GRID Data Specification.

5.23 Whereas the general index, based on EUROSTAT data for average labour cost for full-time employees in industry and services, gives a fairly intuitive picture of the relative differences including mandatory manpower costs, it is based on an average formed by a lower skilled and lower mobility labour pool. For certain functions (e.g. S and P) the assumption of at least regional pseudo-competitive markets is worth investigating. For this reason a second index was constructed.

5.24 Salary correction applies to manpower compensation costs for all functions carried and reported by the firm as direct salary in the accounting system, i.e. as cost type direct salary (1) in accordance with Call C, rev 1.4 of 2008-04-15 (art 6.04, first item). Services bought (outsourced) also contain labour contents to an unknown degree and cost. No adjustment is made of the cost for services bought since that would entail additional assumptions as to the origin of the service provider, the type of services procured and the staff intensity per type of service procured, none of which can be supported by audited information in this benchmarking. If outsourcing is made to achieve more competitive operating costs, which can be assumed since according to results in the interim report on Static results (R1) it is more prevalent in high labour-cost countries, the policy implies that bias is not introduced if the outsourced labour cost corresponds to average European compensation levels for the sector.

5.25 The Europe TSO index is formed by the observed average manpower compensation reported by the operators in e³GRID, optionally decomposed on function. Detailed data for this construction is disseminated to each participant in the Summary sheets for each run. The index is illustrated by the lightred blue curve bars in Figure 5-3 showing some interesting differences with respect to the general index. The hypothesis of regional stickiness for salaries (German-speaking, Nordic, Iberian peninsula) is not contradicted by the data. For countries with several operators, an unweighted average was used for the index. Some missing observations and two outliers make it necessary to revise the index for final use. The regional index (dark blue bars in Figure 5-4 is interesting as it is exogenous to the firm and potentially representative of salary formation for parts of the TSO staff effectives. However, as the set partitioning for the countries in the set is not subject to any deeper validation, the final results rely on the individual index with the regional index represented in the sensitivity analysis (cf. subsection 9.6, page 140).

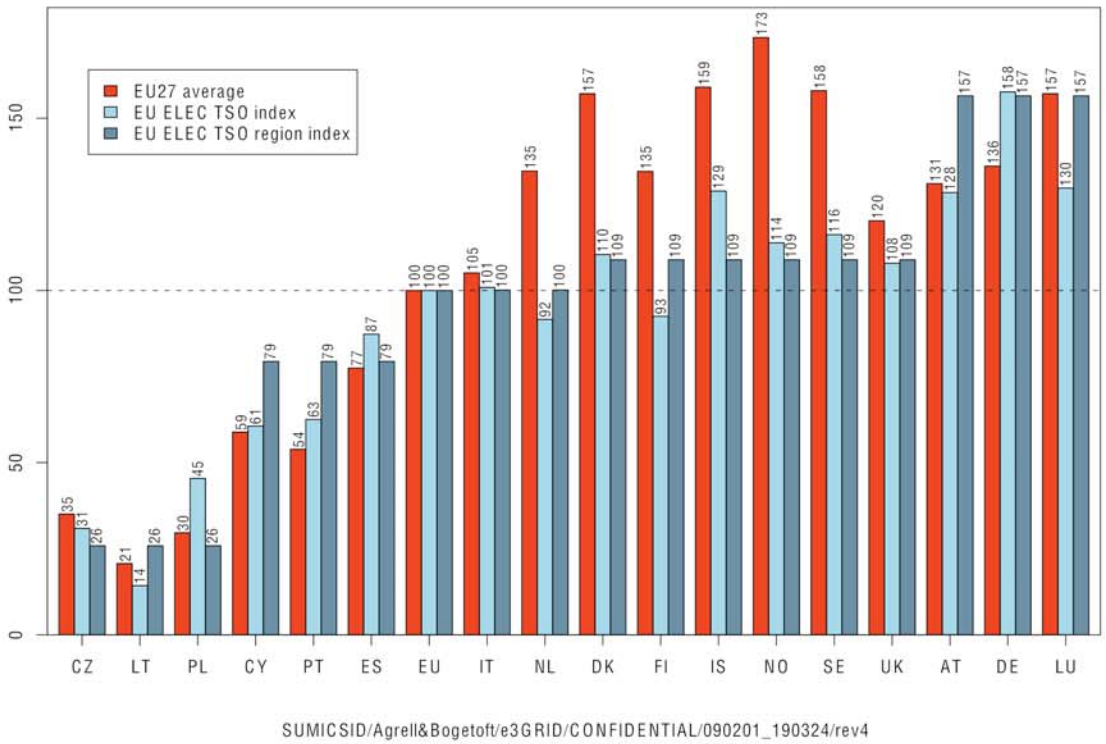


Figure 5-3 Manpower compensation indexes EU27 average 2006, and Europe TSO and regional TSO index.

5.26 Manpower compensation costs are corrected using two indexes. The detailed results only contain data for the sector-specific Europe TSO index.

5.9 Overhead allocation keys

5.27 To assure a standardized allocation of administrative overhead costs, an allocation key based on staff intensity was defined in Call C and its templates. For operators with validated staff head count in the functions, this allocation key has been used to allocate costs for A. For operators with unvalidated or missing staff count for relevant functions, a default index has been used. The default index is defined as the average staff intensity in the core functions for full-service operators (reporting functions S and X) using data 2008-08-16. 7.31. Preliminary findings where overhead was allocated using an fte-key for the functions C and M were presented in the interim report R1. For operators with missing or invalid staff count, the key X 5.6%, S 24%, P 7.9% C 10.6% M 51.9% (rounded figures) was used.

Since the scope analyzed is enlarged to encompass all of support A in the final report, no allocation key is used, since we consider C+P+M+A together.

5.28 No overhead allocation key is necessary in the final run.

5.10 Asset grouping

5.29 The asset groups for the assets in Call C are formed using sensitivity analysis as in ECOM+ 2003 and 2005, where the uncorrected unit cost is shown to be fairly stable with respect to the aggregation policy. The asset grouping has no major importance in this study, since asset data is collected on an asset-item level. However, as a finer disaggregation gives more degrees of freedom to tailor the weights and to capture country specifics, we have chosen to work with a grouping policy such as in Table 5-2 where the number refers to part of the asset item code, cf. Call X. The relative share and development of the asset groups are illustrated in Figure 5-4 below. In terms of shares, the picture is relatively stable. Lines with circuit ends correspond to about 78% of the asset base, very slowly decreasing over time (down from 79% in 1964) compared to e.g cables slowly growing from 5.2% in 1964 to 5.5% in 2006. However, the reinforcement of the grids is visible in the growing share for circuit ends and transformers (from 38.5% to 40.1%). In absolute terms, the grid assets are in stable growth. In all, the asset base has doubled over the horizon (e.g. +80% for lines in Figure 5-4), but the absolute number is not corrected for the aggregation of early assets in some cases.

Table 5-2 Asset grouping in e³GRID.

Asset class	Asset code (Call X)
Lines	10
Cables	20
Circuit ends	30
Transformers	40-41
Compensating devices	50-51
Series compensations	60-61
Control centers	70
Other assets (HVDC)	91

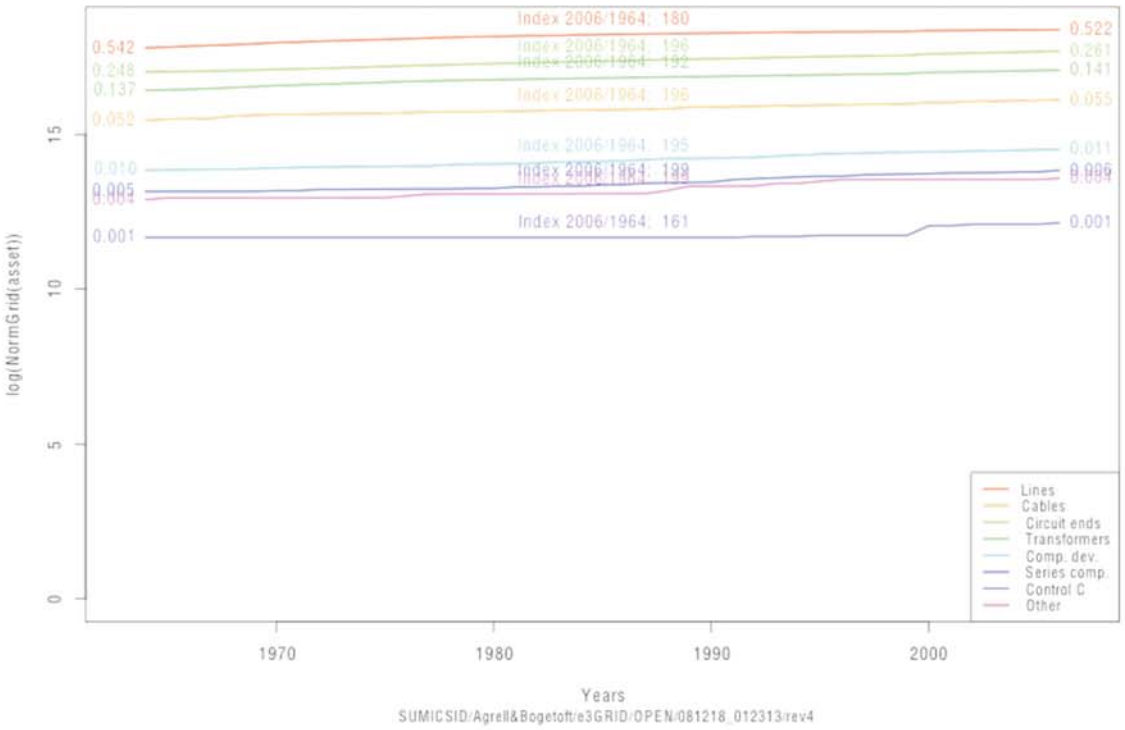


Figure 5-4 Development of asset groups (normalized Capex), logarithmic scale, ends indicate share of total normalized capital, midpoint index normalized asset capex 2006/1964.

5.30 The eight assetgroups used in the final run correspond to classes of assets with meaningful volumes to average. The aggregation of groups has in reality no importance for the results.

5.11 Asset normalization weights

5.31 Each asset weight derives from a system of combined engineering and accounting information constructed independently by Tractebel Engineering on the basis of a large number of construction projects for international transmission operators. The weights are defined relatively in each groups and then consolidated between asset groups. The original basis for the weights are described in the ECOM+ 2005 study by Agrell and Bogetoft (2005), but these weight have been adjusted internally, extended to cover more types, and updated to 2006 level in connection with the present study, as explained below. They are therefore a good starting point, but they have been modified to some extent because of information from other external sources, most notably the studies by ICF

Consulting, PB Associates, Hirst (2000) and ELFORSK (cf. references). Regarding these external validations, it is worthwhile to emphasize that technical evaluations are not unique. This is well known also from other studies, a good illustration of which is the variation of expert evaluations derived by the regulator and the distribution companies in Chile, cf. Agrell and Bogetoft (2003). As the normalization is intended to correspond to the average standardized Capex for a European operator, the mean normalized value was compared to the mean standardized Capex, see below.

5.32 In summary, the primary sources used to calibrate the common weights system in the e³GRID study were a) the relative weights provided by the Tractebel Engineering, b) the relative weights from the ECOM+ studies and regulatory reference systems in three countries and c) a series of external validations using published data. We emphasize that the sensitivity of the results are in general not high when it comes to individual weights. This is understandable since many assets affect the total cost norm.

5.33 In summary, therefore, each weight is intended to reflect the best possible information available on the average European cost of maintaining and operating one unit of the asset.

5.34 First, to determine Capex weights one can use external experts to validate the costs of constructing (or operating) one unit (piece count, circuit km, MVA, etc) of an asset *a** under average European conditions.

5.35 Second, the Opex weights can be calibrated by combining the weights derived by the consultants with overall cost drivers. It is common to allocate operating costs in relation to capital values. This suggests that the Opex and Capex weight shall be proportional. There is however no reason to assume the same proportionality factor for the different assets groups. Cables for example are very expensive in terms of Capex but relative inexpensive in terms of Opex. One can therefore assume group specific proportionality factors as in

$$w_a = \beta_g v_a$$

when *a* belong to group *g*. The proportionality factors "$_g$ are determined through analysis of detailed cost data for operators and validated with the technical experts. The usefulness of this approach depends of course on the asset groups implemented. The relevant grouping must strike a balance between being detailed and estimated on only few weights and being more aggregate with the possibility of extending the use of a given proportionality factor too far. To guide this balance, one can use the relative Opex weights derived by the experts. If two assets have very

different Opex weight proposals from the TSOs, they should allocated to different groups unless the Capex weights have the same differences. While thick line may be substantially more expensive in terms of Capex, the extra maintenance costs may not be as high. This would suggest that lines in this calibration should be split in sub-groups. The Opex weights in this release are constructed in two steps. First, relative weights are applied to the groups based on detailed information from a set of operators. Second, the normalized Opex metric is adjusted as to coincide with the mean standardized Opex for the operators in the study. The ratio (mean normalized Opex to mean standardized Opex) was estimated to 1.034, i.e. within 3.4%.

5.36 The weight system is based on a system of relative weights with assetgroups, based on average costs from independent engineering studies, aggregated across groups and calibrated to equate average European costs in the sample.

5.12 Exchange rate conversion

5.37 All operating costs and the final investment amounts (Capex) are converted to EUR using average annual exchange rates (if applicable) between the national currency and EUR.

5.38 The common currency is defined as EUR, base year 2006, all conversions of operating costs are defined using average annual exchange rates.

6. Model specification

6.1 Variable selection principles for efficiency analysis

6.01 *Robustness*. The model specification and results must be robust to foreseeable cost, technology and institutional changes to guarantee stable incentive provision and minimization of the regulatory risk. Specifications that rely heavily on specific process information, e.g., may become obsolete with technological progress.

6.02 *Verifiability*. An efficiency measurement model used in incentive regulation must be based on verifiable information. Use of poorly defined or private information is directly encouraging opportunistic action. Worse, in yardstick regulation, distorted information may directly affect the incentives of complying firms.

6.03 *Unambiguous*. The model's definitions have to be unambiguous to withstand challenges related to conflicting interpretations, e.g. over time and organizational levels.

6.04 *Output (correlated)*. As discussed at length in Agrell and Bogetoft (2003a) *Dynamic Regulation*, the most robust and least long-run costly regulation regime will be implemented with close definition at the output side and high aggregation on the input side. We pursue this strategy in this report by allocating more effort to the long-run output specification than the (transitional) input problems. The output orientation also yields a process independent model, which strengthens the robustness condition above and creates clear signals of regulatory non-involvement in the operations.

6.05 *Minimal structural impact*. The variables should be defined as to enable the model to capture efficiency with equal precision across firms with varying size, organization and output profile. This means that *bias* should be avoided if possible already in the variable specification phase.

6.06 *Feasibility*. A regulatory model must show feasible results for any imaginable outcome to limit regulatory discretion. In incentive regulation, we note the problem of superefficiency, where the DEA program may fail to find an efficiency estimate for certain production profiles. Superefficiency is not a problem in a SFA context and we refer the reader to the discussion in Agrell and Bogetoft (2004), Agrell, Bogetoft and Tind (2005).

6.2 Variable classification

6.07 The classification of variables and parameters for the models is illustrated in Figure 6-1 below. C is the cost for the activity, X are technical outputs, subject to decisions by the firm. The class of outputs Y is made of exogenous indicators for the results of the regulated task, such as typically variables related to the transportation work (energy delivered etc), capacity provision (peakload, coverage in area etc) and service provision (number of connections, customers etc). The class of outputs Q contains elements concerning the quality level of the transmission of electricity (e.g. in terms of energy not supplied due to technical problems). Finally, the class of structural variables Z contains parameters that may have a non-controllable influence on operating or capital costs without being differentiated as a client output. In this class we find indicators of geography (topology, obstacles), climate (temperature, humidity, salinity), soil (type, slope, zoning) and density (sprawl, imposed feed-in locations). However, it is common to find the effects of a particular control in Z correlated with Y and/or cancelled with other controls in Z.

6.08 The controllable input is C in this benchmarking, assumed to be the cost consequence of a given grid configuration X. The technical assetbase X is then in this context considered as an output, although it is a controllable input, *strictu senso*, to cater for some exogenous future generation and load scenario Y at a given level of system stability, Q. However, since there are considerable methodological problems and risks for adverse interpretations associated with output-based benchmarking of transmission systems, the configuration (dimensioning and evolution) of the grid is not subject to evaluation in this context. Further details about this principle and the alternative approaches are found in Agrell and Bogetoft (2003b).

6.09 One practical consequence of the grid-output focus is that the exogenous variables Y and Q, as well as the set of relevant conditions in Z, are assigned a secondary role in the model specification. To guarantee the correct incentive properties for all firms in the best-practice model, which is a different focus from the average-cost models resulting from e.g. regressions, the grid X has to be represented. Additional variables (C,Q,Z) are then complements to assure structural comparability and/or to act as modifiers to the asset normalizations.

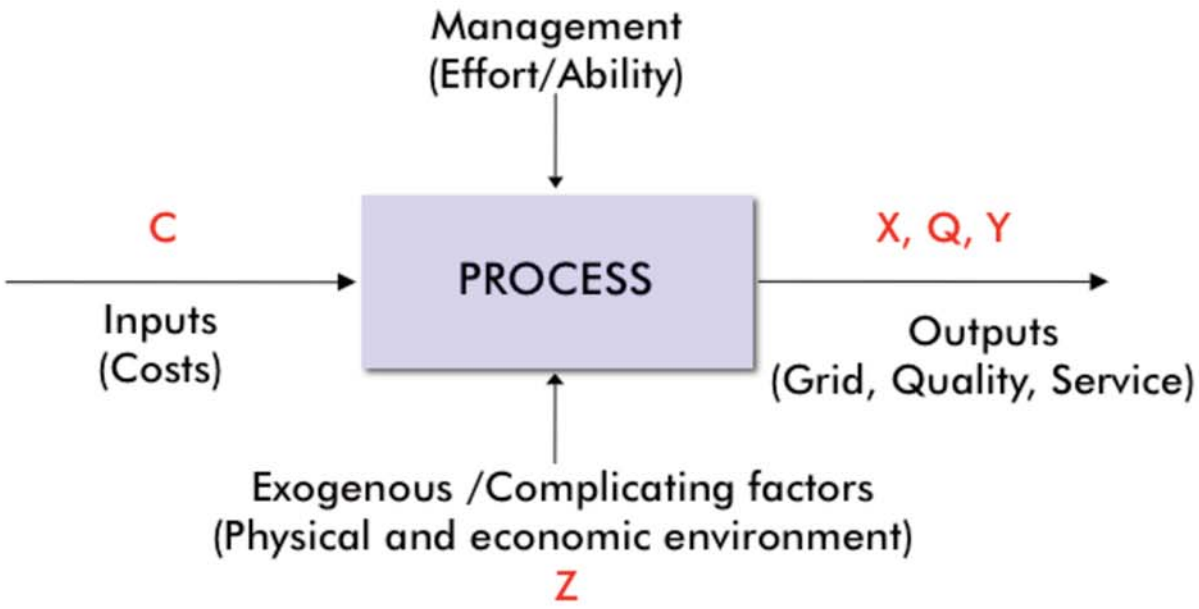


Figure 6-1 Variable classification.

6.3 Estimation procedure

6.10 The average cost estimation procedure is organized in three steps, cf. Figure 6-2, where the final outcome serves to inform the final choice of variables for the benchmarking models. Note that average-cost models are based on different behavioural assumptions than best-practice models and that no mechanic translation can be made of the results from the prior to the former. We recall that the criteria stated above to select benchmarking variables are not all necessary if the focus is limited to a single-short statistical estimate of the average sector costs for e.g. a particular task.

6.11 The first phase (OLS 1) investigates the relationship between any resources (controllable variables X) and the resulting costs C(X). This step is partly tautological as the normalization of the grid asset base in both Capex and Opex is made to observed costs. I.e., the relative weights used above to create normalized asset groups are scaled as to award, in average, the full Opex and Capex for the given grid. This is a direct consequence of the definition to be pegged to *average European costs,* for which there exists no better standardized database than the current study.

6.12 The second phase (OLS 2) aims at the validation of the explanation of the normalized grid variables (Totex, Opex and Capex) through the exogenous variables that characterize the service output. These models serve a validation purpose only and to the extent the intermediate variables can be adequately explained by the exogenous variables, the latter can be omitted from the further analysis.

6.13 The third phase (OLS) is based on the resulting model from OLS 1 and potential subsets of the available variables of type Y and Z from OLS 2. The base model is confronted with potential single-term additions of variables, measured through their t-values (analogous to p-values). Added variables contribute to explaining observed costs (primarily standardized Totex) through a reduction of the mean squared error (or analogously, an increase in the adjusted r^2, a measure of fit). However, not to over-parametrize the model to a small dataset, penalizing functions, such as the Akaike or Bayes Information Criteria (AIC and BIC, respectively) are used to guide the process. As long as the information criterion is decreasing, meaning that the added variables are "adding value" to the model, the forward procedure continues to select variables.

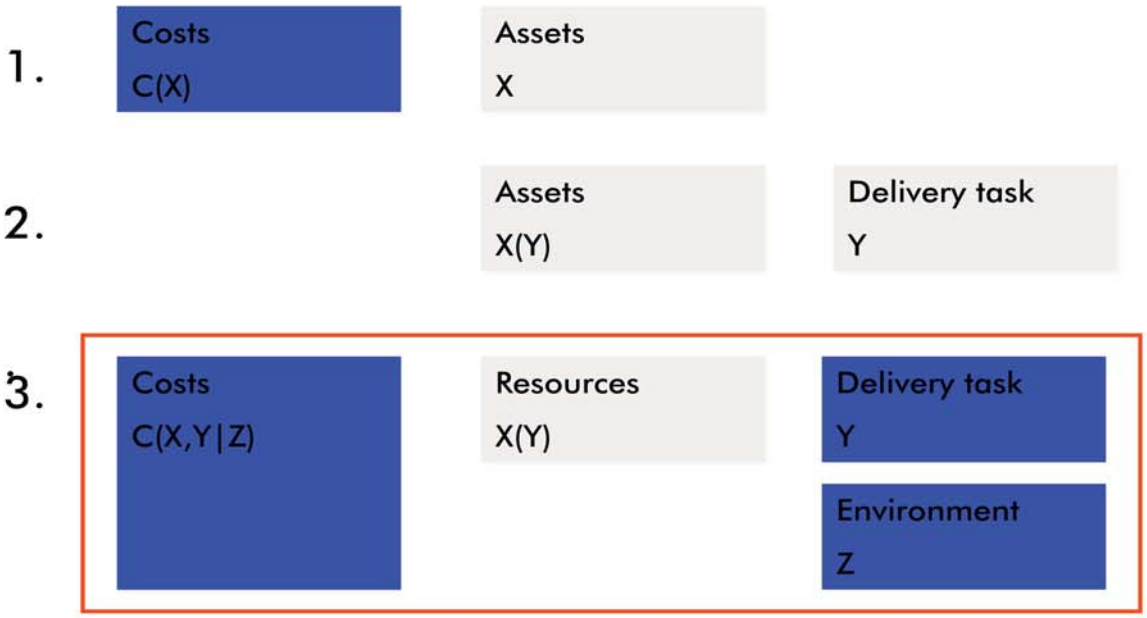


Figure 6-2 Average cost function estimation process.

6.14 The forward model specification is just one alternative, the others being backward reduction from a complete model, stepwise forward-backward and exhaustive searches. As the current dataset of 22 observations for 2006 is far smaller than the potential set of at least 78 variables, not counting potential combinations, backward reduction is not feasible. Furthermore, since the outcome of the process is not the final stage in the model specification, it was not considered relevant to run exhaustive enumeration over likely ineligible model specifications, albeit this might have a purely statistical interest. The objective with any stepwise procedure for a limited data set should be to produce a subset of relevant variables for further analysis, not a single model specification, and this was believed to have been successful with the current procedure.

6.4 Methods

6.15 In each step in the stepwise procedure was applied:

1. Ordinary least squares regression (OLS)
2. Robust regression using weighted least squares as in Yohai (1987).
3. Regression diagnostics of influential observations and multicollinearity using the methods by Belsley, Welsch and Kuh (1980).

6.16 In addition, partial residual plots were used to qualitatively evaluate the impact of variable candidates given the various data sources for e.g. output indicators.

6.5 Stepwise procedure

6.17 Below are documented the OLS and robust regression results for the stepwise procedure. The information criterion used here was the Bayesian information criterion (BIC), also known as Schwarz's Bayesian criterion (SBC), for one or several fitted model objects for which a log-likelihood value can be obtained, according to the formula

$$n \ln (SS\ (Res)_p) + [\ln (n)]p' - n \ln (n)$$

where $SS\ (Res)_p$ is the residual sum of squares for the subset with p' variables considered and n is the number of observations. As described by Schwarz (1978), the second term in the criterion penalizes the addition of terms beyond a substantial reduction of the sum of the residuals. The Akaike (1969) information criterion is similar, but with a fixed penalty of 2 rather than ln (n), which is indicated to give too large models in e.g Judge et al. (1980). Below we document a run with indicators with at most 5 missing observations and a cut-off value (t) = 1.8, corresponding to a p-value of 0.044. For each step, the regression report, the robust regression report, a Belsley analysis of multi-collinearity, the BIC value and selected variables are listed. The full table of t-values per iteration is found as Table 6-2 below.

Preparatory Step

```
.... removing empty columns: yEnergy.del.res yEnergy.del.com yEnergy.del.ind
yEnergy.losses.transm yEnergy.losses.distr yEnergy.gen.hydro yEnergy.gen.DG yEnergy.gen.CHP
yPower.gen.chp yPower.interconnect yPower.peak yPower.reserve yService.res yService.pop.urban
yService.res.urban yService.connection.ehv yService.connection.hv yService.market
yService.market.volume yService.market.value yService.market.incumbent yEnv.area2 yEnv.area.lake
yEnv.area.roads yEnv.area.alps yEnv.area.resid zAge6 zAge7 zAge8
```

Step 1

```
BIC for new model:  370.5575

Call:
lm(formula = paste("lvar~", basem, sep = ""))

Residuals:

   Min     1Q Median     3Q    Max
-809.1  105.7  755.1 1152.7 1914.1

Coefficients:
          Estimate Std. Error t value Pr(>|t|)
yNGTotex 0.0012114  0.0004611   2.627   0.0158 *
---
Signif. codes:  0 '***' 0.001 '**' 0.01 '*' 0.05 '.' 0.1 ' ' 1

Residual standard error: 978.1 on 21 degrees of freedom
Multiple R-squared: 0.2473,     Adjusted R-squared: 0.2115
F-statistic: 6.901 on 1 and 21 DF,  p-value: 0.01575

Call:
lmrob(formula = mod.lm)

Weighted Residuals:
   Min     1Q Median     3Q    Max
-779.8  116.6  760.0 1155.2 1914.9

Coefficients:
          Estimate Std. Error t value Pr(>|t|)
yNGTotex 0.0011865  0.0003412   3.477  0.00225 **
---
Signif. codes:  0 '***' 0.001 '**' 0.01 '*' 0.05 '.' 0.1 ' ' 1

Robust residual standard error: 1132
Convergence in 7 IRWLS iterations

Robustness weights:
 2 weights are ~= 1. The remaining 20 ones are summarized as
   Min. 1st Qu.  Median    Mean 3rd Qu.    Max.
 0.7564  0.9012  0.9543  0.9312  0.9819  0.9989

Algorithmic parameters:
tuning.chi         bb tuning.psi refine.tol    rel.tol
 1.5476400  0.5000000  4.6850610  0.0000001  0.0000001
 nResample     max.it    groups    n.group   best.r.s   k.fast.s      k.max  trace.lev compute.rd
       500         50         5        400          2          1        200          0          0

seed : int(0)
```

6.18 yNGTotex condition index = 1 Good, multicollinearity not a problem

Step 2

```
Selecting variable:  yService.price.ind
Current model:  0+yNGTotex+yService.price.ind
BIC for new model:  317.0158

Call:
lm(formula = paste("lvar~", basem, sep = ""))

Residuals:
Min      1Q  Median      3Q     Max
-519.89 -329.99  -49.57  251.76  770.56

Coefficients:
                    Estimate Std. Error t value Pr(>|t|)
yNGTotex           -4.929e-04  2.555e-04  -1.929   0.0688 .
yService.price.ind  1.448e+04  1.526e+03   9.485 1.23e-08 ***
---
Signif. codes:  0 ‘***’ 0.001 ‘**’ 0.01 ‘*’ 0.05 ‘.’ 0.1 ‘ ’ 1

Residual standard error: 388.2 on 19 degrees of freedom
  (1 observation deleted due to missingness)
Multiple R-squared: 0.8748,     Adjusted R-squared: 0.8617
F-statistic:  66.4 on 2 and 19 DF,  p-value: 2.668e-09

Call:
lmrob(formula = mod.lm)

Weighted Residuals:
    Min      1Q  Median      3Q     Max
-498.46 -310.50  -28.41  282.23  783.88

Coefficients:
                    Estimate Std. Error t value Pr(>|t|)
yNGTotex           -4.882e-04  1.423e-04  -3.431  0.00280 **
yService.price.ind  1.420e+04  1.444e+03   9.838 6.84e-09 ***
---
Signif. codes:  0 ‘***’ 0.001 ‘**’ 0.01 ‘*’ 0.05 ‘.’ 0.1 ‘ ’ 1

Robust residual standard error: 395.3
Convergence in 9 IRWLS iterations

Robustness weights:
 2 weights are ~= 1. The remaining 19 ones are summarized as
   Min. 1st Qu.  Median    Mean 3rd Qu.    Max.
 0.6737  0.9032  0.9446  0.9164  0.9829  0.9961

Algorithmic parameters:
tuning.chi         bb tuning.psi refine.tol    rel.tol
 1.5476400  0.5000000  4.6850610  0.0000001  0.0000001
 nResample     max.it    groups    n.group   best.r.s   k.fast.s      k.max  trace.lev compute.rd
       500         50         5        400          2          1        200          0          0

seed : int(0)
yNGTotex  condition index = 1  Good, multicollinearity not a problem
```

6.19 yService.price.ind condition index = 2.369700 Good, multicollinearity not a problem

Step 3

```
Selecting variable:  zAge5
Current model:  0+yNGTotex+yService.price.ind+zAge5
BIC for new model:  299.2842

Call:
lm(formula = paste("lvar~", basem, sep = ""))

Residuals:
    Min      1Q  Median      3Q     Max
-511.42 -187.54  -21.11  176.26  618.46

Coefficients:
Estimate Std. Error t value Pr(>|t|)
yNGTotex           -5.375e-04  2.339e-04  -2.298   0.0345 *
yService.price.ind  1.907e+04  2.205e+03   8.647 1.25e-07 ***
zAge5              -1.821e+01  7.055e+00  -2.582   0.0194 *
---
Signif. codes:  0 ‘***’ 0.001 ‘**’ 0.01 ‘*’ 0.05 ‘.’ 0.1 ‘ ’ 1

Residual standard error: 345.5 on 17 degrees of freedom
  (2 observations deleted due to missingness)
Multiple R-squared: 0.907,      Adjusted R-squared: 0.8906
F-statistic: 55.27 on 3 and 17 DF,  p-value: 5.603e-09

Call:
lmrob(formula = mod.lm)

Weighted Residuals:
     Min       1Q   Median       3Q      Max
-501.738 -172.036   -3.938  189.856  624.517

Coefficients:
                     Estimate Std. Error t value Pr(>|t|)
yNGTotex           -5.295e-04  1.109e-04  -4.773 0.000177 ***
yService.price.ind  1.896e+04  2.093e+03   9.062 6.42e-08 ***
zAge5              -1.861e+01  7.077e+00  -2.630 0.017562 *
---
Signif. codes:  0 ‘***’ 0.001 ‘**’ 0.01 ‘*’ 0.05 ‘.’ 0.1 ‘ ’ 1

Robust residual standard error: 329.8
Convergence in 8 IRWLS iterations

Robustness weights:
 4 weights are ~= 1. The remaining 16 ones are summarized as
   Min. 1st Qu.  Median    Mean 3rd Qu.    Max.
 0.7000  0.8385  0.9546  0.8993  0.9781  0.9976

Algorithmic parameters:
tuning.chi         bb tuning.psi refine.tol    rel.tol
 1.5476400  0.5000000  4.6850610  0.0000001  0.0000001
 nResample     max.it    groups    n.group   best.r.s   k.fast.s      k.max  trace.lev compute.rd
       500         50         5        400          2          1        200          0          0

seed : int(0)
```

6.20 yNGTotex condition index = 1 Good, multicollinearity not a problem

6.21 yService.price.ind condition index = 2.431523 Good, multicollinearity not a problem

6.22 zAge5 condition index = 4.377439 Good, multicollinearity not a problem

Step 4

```
Selecting variable:  yEnv.rain
Current model:  0+yNGTotex+yService.price.ind+zAge5+yEnv.rain
BIC for new model:  294.9509

Call:
lm(formula = paste("lvar~", basem, sep = ""))

Residuals:
    Min      1Q  Median      3Q     Max
-557.80 -139.72   21.20  156.34  425.60

Coefficients:
                   Estimate Std. Error t value Pr(>|t|)
yNGTotex          -6.285e-04  2.036e-04  -3.087  0.00707 **
yService.price.ind  1.457e+04  2.537e+03   5.741 3.04e-05 ***
zAge5             -2.696e+01  6.889e+00  -3.913  0.00124 **
yEnv.rain          9.592e+00  3.604e+00   2.661  0.01708 *
---
Signif. codes:  0 ‘***’ 0.001 ‘**’ 0.01 ‘*’ 0.05 ‘.’ 0.1 ‘ ’ 1

Residual standard error: 296.5 on 16 degrees of freedom
  (2 observations deleted due to missingness)
Multiple R-squared: 0.9355,     Adjusted R-squared: 0.9194
F-statistic: 58.05 on 4 and 16 DF,  p-value: 2.529e-09

Call:
lmrob(formula = mod.lm)

Weighted Residuals:
    Min      1Q  Median      3Q     Max
-570.28 -142.15   19.47  152.77  419.36

Coefficients:
                   Estimate Std. Error t value Pr(>|t|)
yNGTotex          -6.355e-04  1.303e-04  -4.877 0.000168 ***
yService.price.ind  1.477e+04  2.327e+03   6.348 9.68e-06 ***
zAge5             -2.771e+01  7.320e+00  -3.785 0.001622 **
yEnv.rain          9.682e+00  2.656e+00   3.645 0.002180 **
---

Signif. codes:  0 ‘***’ 0.001 ‘**’ 0.01 ‘*’ 0.05 ‘.’ 0.1 ‘ ’ 1

Robust residual standard error: 323.3
Convergence in 10 IRWLS iterations

Robustness weights:
 one weight is ~= 1. The remaining 19 ones are summarized as

   Min. 1st Qu.  Median    Mean 3rd Qu.    Max.
 0.7367  0.8945  0.9669  0.9377  0.9899  0.9983
```

```
Algorithmic parameters:
tuning.chi         bb tuning.psi refine.tol    rel.tol
 1.5476400  0.5000000  4.6850610  0.0000001  0.0000001
 nResample     max.it    groups    n.group   best.r.s   k.fast.s      k.max  trace.lev compute.rd
       500         50         5        400          2          1        200          0          0

seed : int(0)
```

6.23 yNGTotex condition index = 1 Good, multicollinearity not a problem

6.24 yService.price.ind condition index = 2.780373 Good, multicollinearity not a problem

6.25 zAge5 condition index = 4.923349 Good, multicollinearity not a problem

6.26 yEnv.rain condition index = 7.42102 Good, multicollinearity not a problem

6.27 No significant addition found - model saturated at level 0.4803365

6.6 Results for stepwise additions

6.28 Detailed regression results are provided for all candidate variables with less than 5 missing observations in Appendix A. The base model is constructed by the normalized Totex grid metric. Absence of significance in this first step normally indicates that the variable is either correlated to the grid proxy (OLS 2) or simply unrelated to the dependent variable (standardized Totex). Single factor results are listed for linear regression in Appendix F.

6.7 Results for quality indicators

6.29 The quality indicator ENS was tested for inclusion towards total standardized costs, Opex, Capex, UC, log(UC/area) and other combinations without any significant results. One model is documented below. We conclude that this indicator is not a solid base for explaining transmission system costs with respect to quality performance. One reason is likely that ENS is the outcome of a stochastic process, governed by partially different factors than those significant for total costs (e.g. exceptional weather conditions) and very difficult to relate in both causality and statistics to the costs a given year.

```
Call:
lm (formula = "dv_Totex~yNGTotex+zENS")

Residuals:
       Min         1Q     Median         3Q        Max
-151935493  -94191893   36036685   58233505  656398172

Coefficients:
         Estimate Std. Error t value Pr (>|t|)
yNGTotex    674.1      108.0   6.239 3.02e-05 ***
zENS       3033.5    19548.0   0.155    0.879
---
Signif. codes:  0 ‘***’ 0.001 ‘**’ 0.01 ‘*’ 0.05 ‘.’ 0.1 ‘ ’ 1

Residual standard error: 204800000 on 13 degrees of freedom
 (7 observations deleted due to missingness)
Multiple R-squared: 0.7556,      Adjusted R-squared: 0.718
F-statistic:  20.1 on 2 and 13 DF,  p-value: 0.0001053
```

Correlation analysis

6.30 Many of the indicators for asset intensity, output and environmental conditions are strongly correlated intra-group and inter-group, as illustrated in Table 6-1 below. The additive use of multiple such indicators in a single model would introduce multicollinearity among indicators and reduce the information value of the estimated coefficients and the evaluation of their statistical significance. Full correlation results are listed in Appendix G.

Table 6-1 Intra-group correlation (Towers indicators).

	zTowers.steel	zTowers.cable	zTowers.wood	zTowers.other
zTowers.steel	1.000000000	-0.138390208	-0.20291168	-0.146977142
zTowers.cable		1.000000000	0.92106350	-0.003881048
zTowers.wood			1.00000000	-0.051562543
zTowers.other				1.000000000

Table 6-2 T-values for candidate variables in step-wise procedure.

	Step			
Variable	1	2	3	4
yEnergy.del	1.205	0.648	1.175	0.269
yEnergy.del.res	0.911	0.555	1.289	0.510
yEnergy.del.com	1.254	0.660	1.254	0.453
yEnergy.del.ind	1.387	0.853	1.204	0.121
yEnergy.losses.distr	1.087	0.293	0.805	0.571
yEnergy.import	2.280	1.421	1.545	0.144
yEnergy.export	0.059	0.102	0.311	0.591
yEnergy.gen.ren	0.378	0.330	0.844	0.072
yEnergy.gen.hydro	1.348	1.819	1.143	0.296
yPower.gen	1.524	0.837	1.165	0.413
yPower.gen.wind	0.083	0.306	0.539	0.057
yPower.gen.solar	0.595	0.609	0.954	0.402
yPower.gen.hydro	2.315	2.324	1.132	0.615
yPower.gen.ren.excl.hydro	0.346	0.437	0.679	0.167
yPower.gen.ren.incl.hydro	1.566	1.628	1.104	0.206
yPower.gen.nonren	1.331	0.464	1.082	0.452
yPower.gen.thermal	1.735	0.626	1.171	0.525
yPower.gen.nuclear	0.318	0.094	0.702	0.125
yPower.gen.gas	2.809	1.580	1.729	**1.675**
yService.pop	**4.802**			
yService.popgrowth	1.367	0.790	1.904	1.032
yService.price.ind	1.445	0.522	0.748	0.759
yService.price.res	1.709	0.710	0.821	0.530
yService.tax	1.340	0.491	0.914	0.834
yEnv.area	0.293	0.624	1.881	0.895
yEnv.area.forest	0.258	0.310	0.535	0.476
yEnv.area.agri	1.182	1.549	**5.354**	
yEnv.temp.summer	1.503	0.473	0.434	0.966
yEnv.temp.winter	1.961	1.419	0.925	1.561
yEnv.temp.max30	1.740	0.656	0.533	1.157
yEnv.temp.min30	2.247	1.162	0.825	1.539
yEnv.rain	1.390	0.912	1.063	1.317
zTowers.steel	4.762	**2.976**		
zTowers.cable	1.073	0.839	0.794	1.336
zTowers.wood	0.992	0.525	0.471	0.656
zTowers.other	0.250	0.387	0.495	1.606
zAge1	0.078	0.409	0.036	0.660
zAge2	0.398	0.379	1.081	1.398
zAge3	0.257	0.359	0.075	0.530
zAge4	0.223	0.173	0.469	0.907
zAge5	0.336	0.343	0.648	0.465
zAgem	0.368	0.081	0.420	0.974
yInd.member	0.913	0.275	0.041	0.500
yInd.eur	1.379	0.968	0.705	0.260
yInd.prod1	1.040	0.751	0.972	0.967
yInd.prod2	1.131	0.709	0.902	1.094
yInd.integration.goods	0.677	0.169	0.132	0.452
yInd.integration.service	0.282	0.153	0.275	0.552
yInd.salary	0.127	0.308	0.141	0.360
yInd.gdp	0.937	0.715	0.933	1.077
yInd.gdpgrowth	0.149	0.772	0.570	0.558
max (t)	4.802	2.976	5.354	1.675

7. Cost analysis

7.1 Overview

7.01 The transmission system operator functions are defined in Chapter 3 of this report; this section is devoted to a qualitative analysis of the actual data from the participating grids. In Table 7-1 an overview of the cost volumes reported for the e³GRID participants is given in EUR with inflation adjustment for the year 2006, but prior to revenue or salary corrections. The content of the table is also reproduced in Figure 7-1 for easy perception.

Table 7-1 Total reported cost (EUR, 2006) no salary adjustment, gross = no revenue adjustments.

	TSOs	9	12	16	22
		2003	2004	2005	2006
OPEX	CM	360,992,926	543,171,684	615,635,278	1,171,350,371
	CMP	595,164,850	803,400,077	951,338,486	1,755,685,413
	CMA	385,485,604	571,854,726	650,072,827	1,285,303,904
	CMPA	619,657,527	832,083,119	985,776,035	1,869,638,946
	CMPS	1,454,317,135	1,809,680,123	2,718,197,011	4,908,656,787
	CMPSX	1,851,257,170	2,647,675,383	4,779,702,989	8,490,901,361
	CMPASX	2,085,429,093	2,907,903,775	5,115,406,197	9,075,236,403
	C	11,545,060	11,855,557	29,106,534	80,904,852
	M	349,447,866	531,316,127	586,528,744	1,090,445,520
	P	24,492,677	28,683,042	34,437,549	113,953,533
	A	234,171,923	260,228,393	335,703,209	584,335,042
	S	1,068,831,531	1,237,825,398	2,068,124,184	3,623,352,883
	X	396,940,035	837,995,259	2,061,505,978	3,582,244,574
CAPEX		1,083,023,722	1,749,248,327	1,964,917,009	3,765,054,844
TOTEX_gross		3,168,452,815	4,657,152,103	7,080,323,206	12,840,291,247
TOTEX_net		1,185,321,229	2,595,290,913	4,630,382,591	8,700,704,660

7.02 The absolute costs in Table 7-1 naturally reflect the number of operators reporting per year and do not immediately lead to any conclusion regarding the cost functions and their treatment. One way to illustrate the cost basis is to present cost shares as in Table 7-2 or average figures for any grid and year, as in Table 7-3 below. As above, the cost is expressed in inflation adjusted EUR (2006), but prior to corrections for revenues and salary costs. Here we note that the larger sample of grids in 2006 indeed have somewhat different profile than the earlier sample, in particular the

2003-2004 group. The 2006 group has considerably higher expenses for system operations, maintenance, planning and support, in addition to higher Capex figures. The same information is contained in Figure 7-3 and Figure 7-2 below. We will now investigate whether this cost difference is merely a question of size.

Table 7-2 Cost shares per function (EUR, 2006 value, no revenue or salary adjustments).

		2003	2004	2005	2006
OPEX	CM	11.4%	11.7%	8.7%	9.1%
	CMP	18.8%	17.3%	13.4%	13.7%
	CMA	12.2%	12.3%	9.2%	10.0%
	CMPA	19.6%	17.9%	13.9%	14.6%
	CMPS	45.9%	38.9%	38.4%	38.2%
	CMPSX	58.4%	56.9%	67.5%	66.1%
	CMPASX	65.8%	62.4%	72.2%	70.7%
	C	0.4%	0.3%	0.4%	0.6%
	M	11.0%	11.4%	8.3%	8.5%
	P	0.8%	0.6%	0.5%	0.9%
	A	7.4%	5.6%	4.7%	4.6%
	S	33.7%	26.6%	29.2%	28.2%
	X	12.5%	18.0%	29.1%	27.9%
CAPEX		34.2%	37.6%	27.8%	29.3%
TOTEX_gross		100.0%	100.0%	100.0%	100.0%
TOTEX_net		37.4%	55.7%	65.4%	67.8%

Table 7-3 Average costs per operator in e3GRID (EUR, 2006 value, no revenue or salary adjustments).

		2003	2004	2005	2006
OPEX	CM	40,110,325	45,264,307	38,477,205	53,243,199
	CMP	66,129,428	66,950,006	59,458,655	79,803,882
	CMA	42,831,734	47,654,561	40,629,552	58,422,905
	CMPA	68,850,836	69,340,260	61,611,002	84,983,588
	CMPS	161,590,793	150,806,677	169,887,313	223,120,763
	CMPSX	205,695,241	220,639,615	298,731,437	385,950,062
	CMPASX	231,714,344	242,325,315	319,712,887	412,510,746
	C	1,282,784	987,963	1,819,158	3,677,493
	M	38,827,541	44,276,344	36,658,046	49,565,705
	P	2,721,409	2,390,254	2,152,347	5,179,706
	A	26,019,103	21,685,699	20,981,451	26,560,684
	S	118,759,059	103,152,117	129,257,762	164,697,858
	X	44,104,448	69,832,938	128,844,124	162,829,299
CAPEX		120,335,969	145,770,694	122,807,313	171,138,857
TOTEX_gross		352,050,313	388,096,009	442,520,200	583,649,602
TOTEX_net		131,702,359	216,274,243	289,398,912	395,486,575

7.03 The previous presentation gives some information about the operators in the study and their costs, but to permit a preliminary analysis, the average values have to be put into relation to the size of the task, i.e. the normalized grid in this context. The average gross cost (EUR, 2006) controlled for grid size is provided in Table 7-4 below. In fact, the average grid size per operator is about equal (size index 91.4%, 100%, 81.4% and 94.7%, respectively) to the earlier years. Nevertheless, the cost intensity per grid unit has increased faster than inflation for almost all functions besides support. The market facilitation and system operations charges have apparently increased more than other operational expenditures. However, as will be shown in the section on these costs, the market facilitation cost increase is primarily a consequence of sample size, including some lumpy items for a few operators. Below, we will investigate if there are differences in the cost development that would justify the hypothesis of divergent technologies and/or managerial efficiency as explanatory factor.

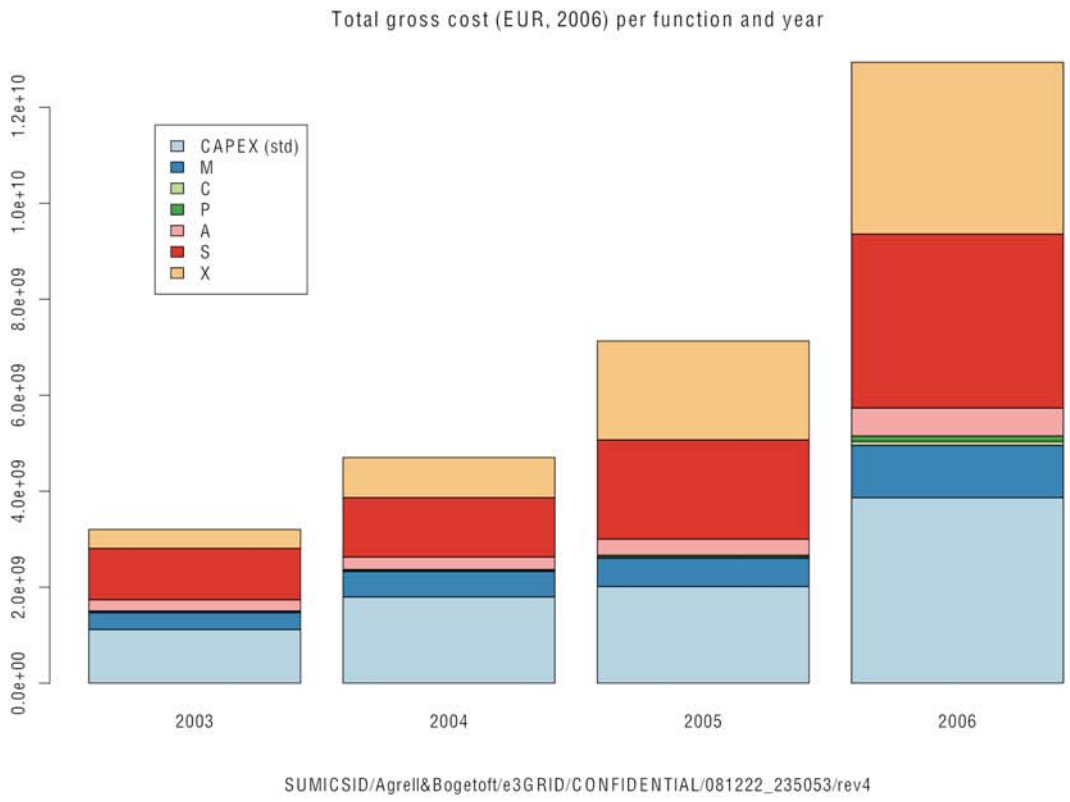


Figure 7-1 Total gross cost (EUR, 2006) per function and year.

Table 7-4 Gross cost per normalized grid unit in e³GRID (EUR, 2006 value).

		2003	2004	2005	2006
OPEX	CM	133	137	143	170
	CMP	220	203	221	255
	CMA	142	145	151	187
	CMPA	229	210	229	272
	CMPS	536	457	632	714
	CMPSX	683	669	1,112	1,235
	CMPASX	769	735	1,190	1,320
	C	4	3	7	12
	M	129	134	136	159
	P	9	7	8	17
	A	86	66	78	85
	S	394	313	481	527
	X	146	212	480	521
CAPEX		399	442	457	548
TOTEX_gross		1,169	1,177	1,647	1,868
TOTEX_net		437	656	1,077	1,265

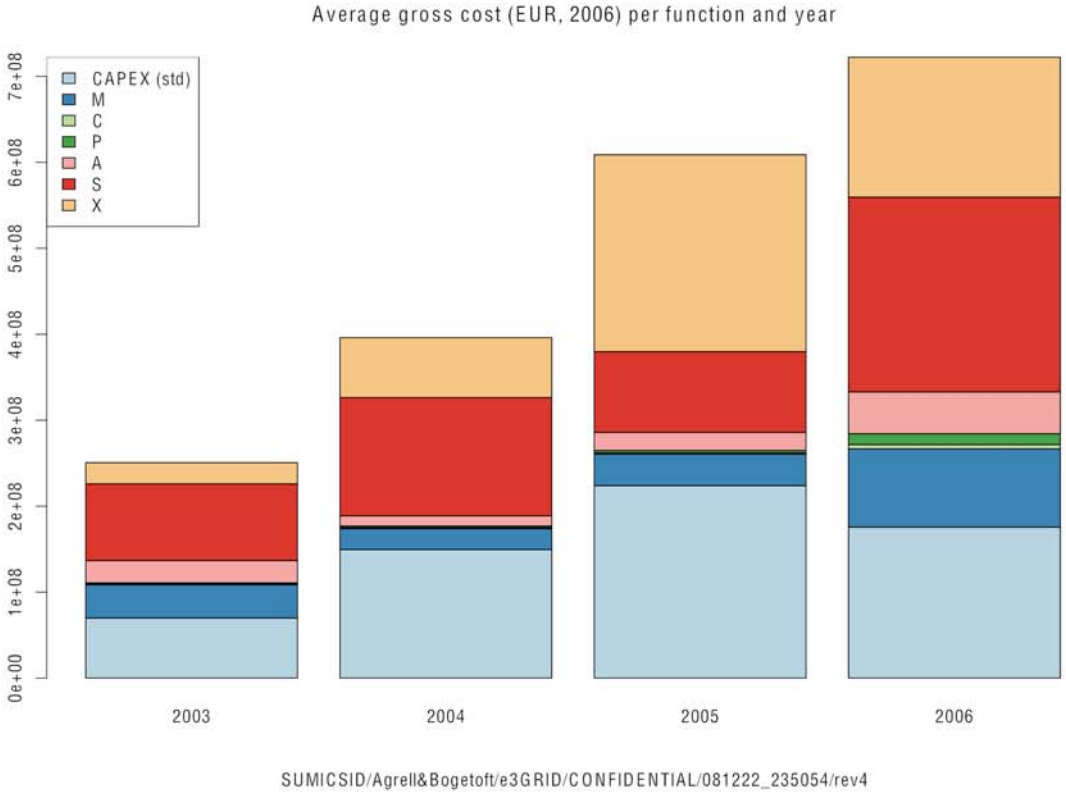


Figure 7-2 Average gross cost (EUR,2006) per function and year.

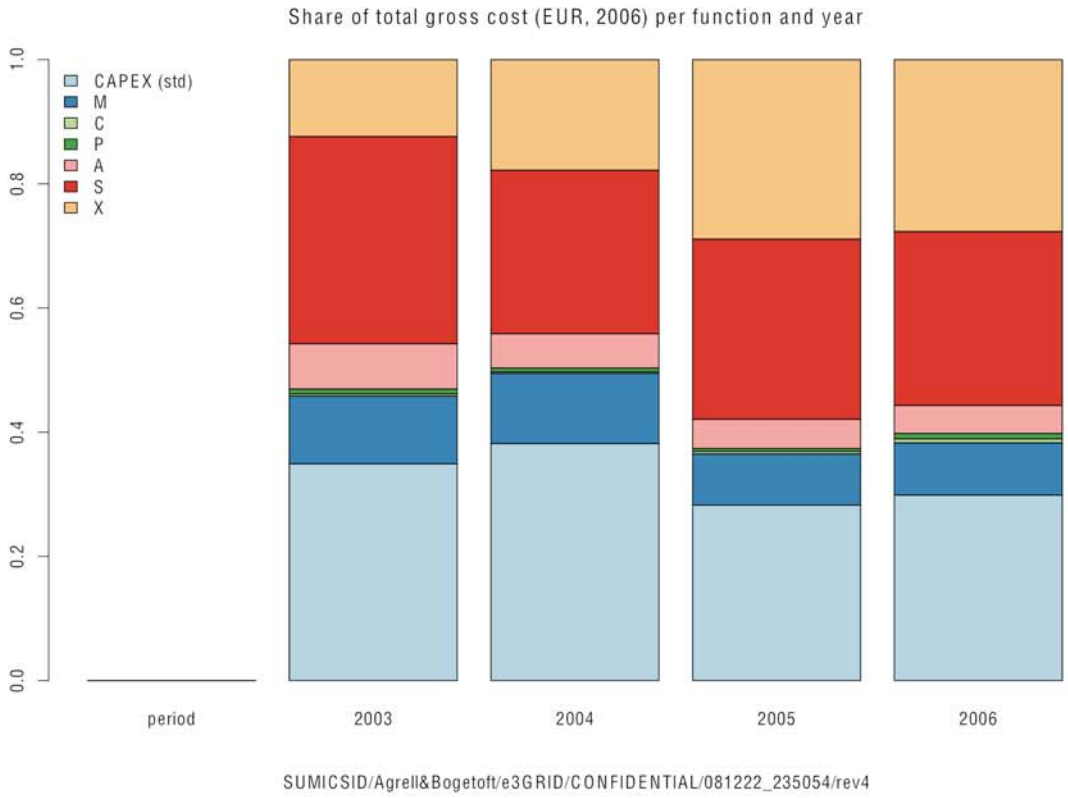


Figure 7-3 Share of total gross cost (EUR, 2006) per function and year.

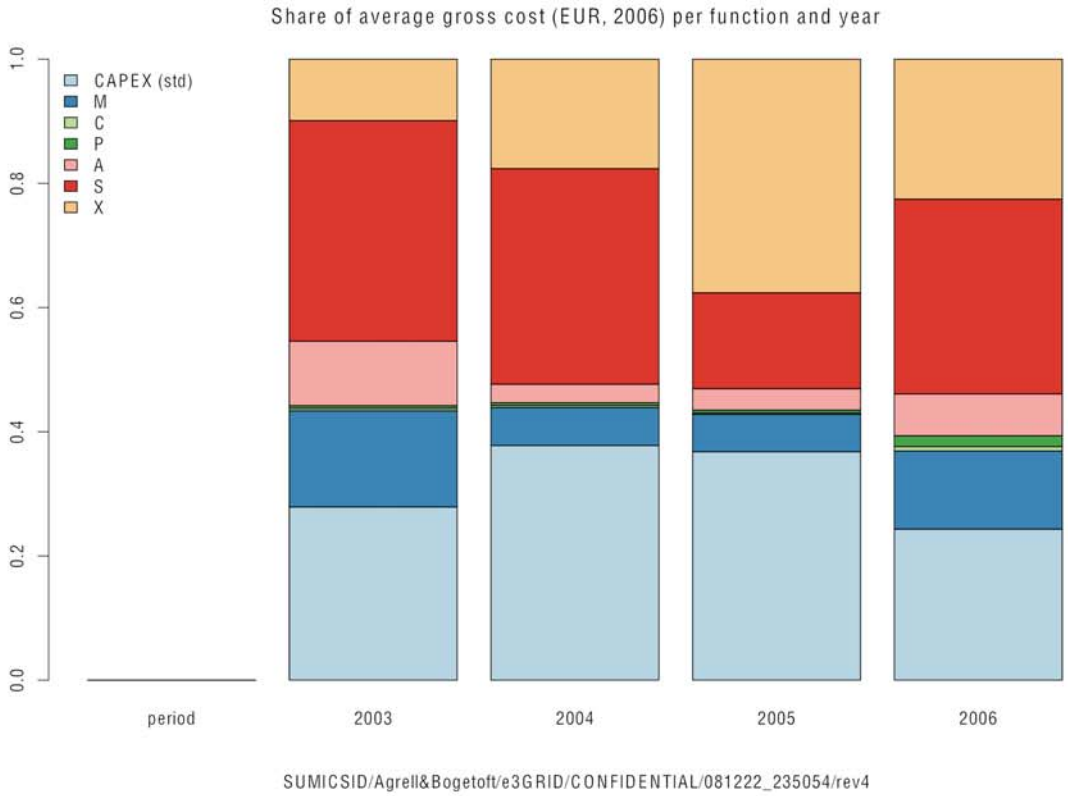


Figure 7-4 Shares per function of average gross costs and year.

7.2 Cost development peers

7.04 The retained model 3 (Grid, Density and Renewables) returns a number of fully efficient operators from the runs with or without outliers. It is generally of interest to consider the cost development for the peers in order to detect specific policies that could explain higher relative performance. In e³GRID, the cost development for the peers has been studied both for the 2003-2006 period (balanced panel) and for the subperiods 2004-2006 and 2005-2006, respectively. Below, we document some insights into the analysis for the panel period 2003-2006. The average below includes all grids for which observations exist during the relevant horizon.

7.05 First, the peer grids are not efficient due to artificially favourable leasing or rental agreements (cf. Figure 7-5) in fact they reduce the amount of leasing during the period contrary to the average grids that increase the leasing volume by 30% over the 4 –year period.

7.06 Second, the peers are significantly stronger in retaining overall operating expenditure (cf. Figure 7-6) that grew only 1% more than load compared to 7% for the average grid. The cost containment is not made through staff reductions (cf. Figure 7-8) but rather through capping non-staff expenses (cf. Figure 7-8). The pattern is particularly clear for maintenance costs (see Figure 7-9 and Figure 7-10). Note that the analysis is index-based, on an absolute level the peer grids have significantly lower staff intensity in maintenance, but with a tendency to increase both in relative salary and head count.

7.07 Third, the support costs that constitute the major source of efficiency catch-up for the average grids are not primary sources of efficiency savings for the peers. In fact, the peers have already achieved considerable economies on support and overhead, the difference in support cost per grid unit is around 33%, controlled for salary differences, inflation and currency. Detailed analysis (not documented in this report) reveal also individual differences within the peer group with respect to support costs.

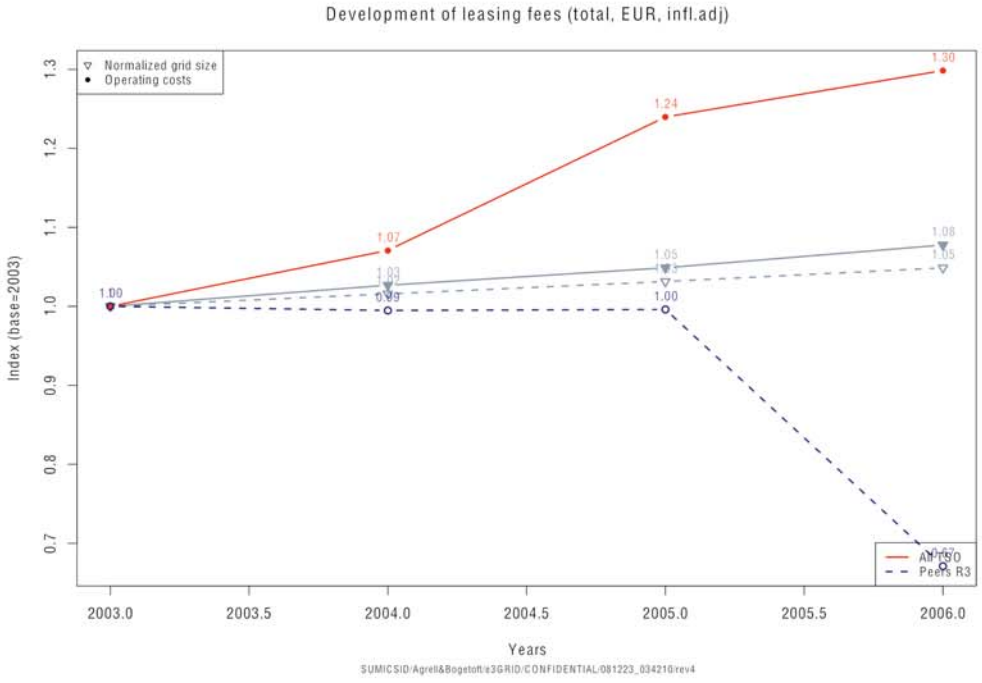


Figure 7-5 Cost development leasing fees peers vs average 2003-2006

(solid lines are development for all TSOs, dotted lines peers in DEA-NDRS, circles represent cost development, triangles grid growth).

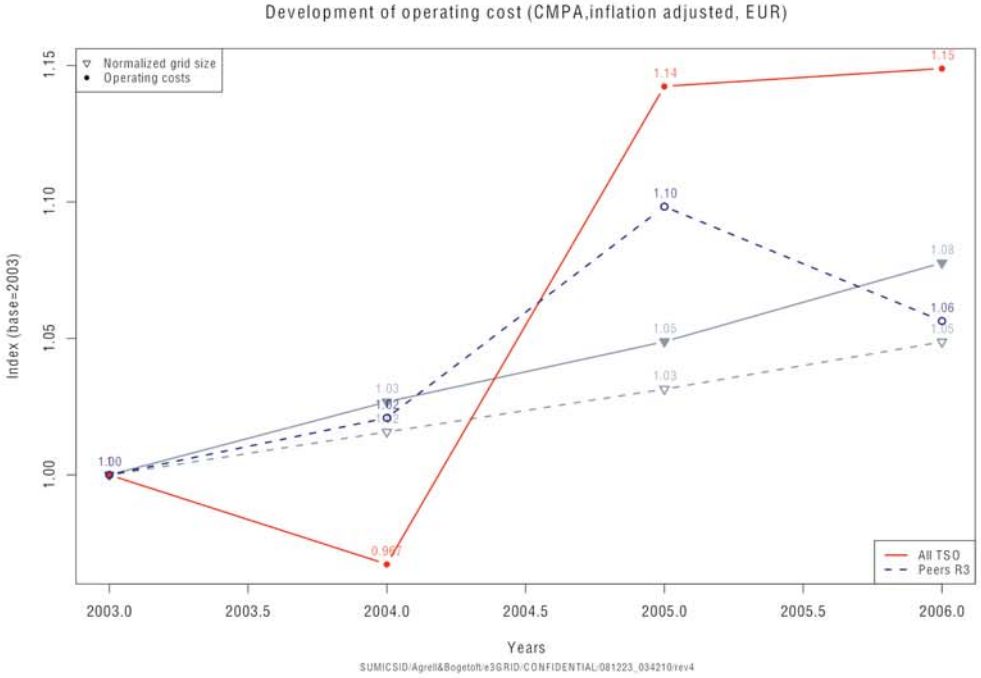


Figure 7-6 Cost development CMPA peers vs average 2003-2006.

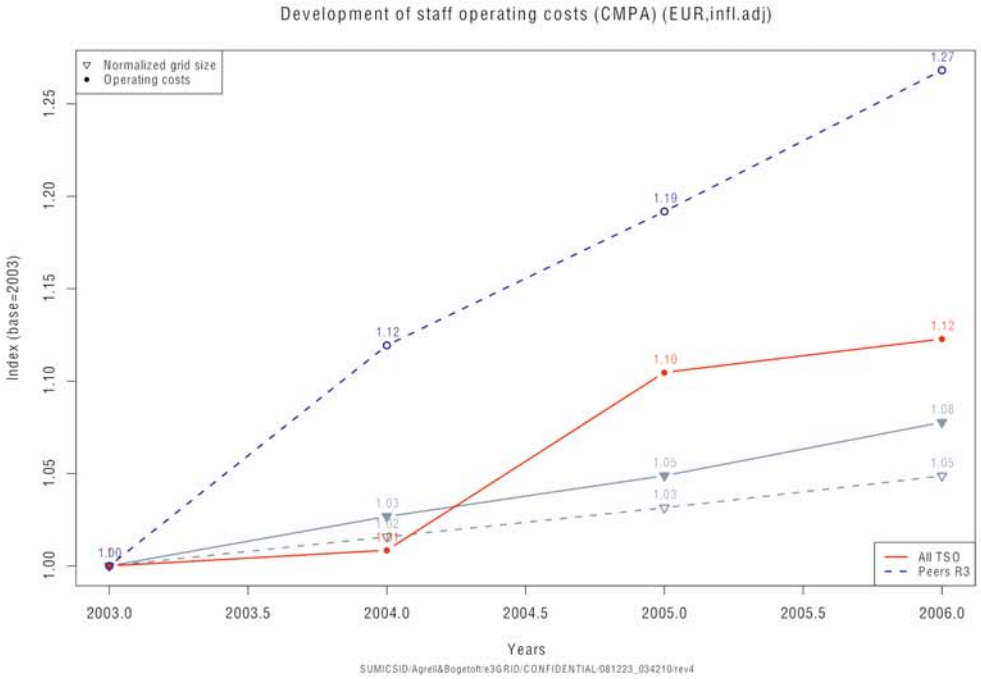


Figure 7-7 Cost development staff CMPA peers vs average 2003-2006.

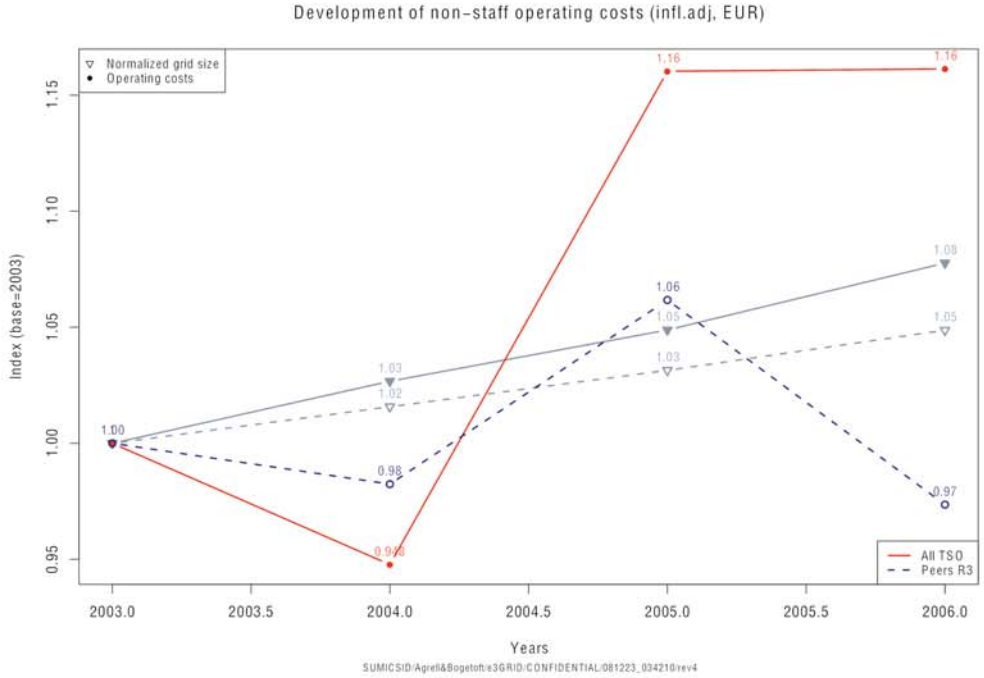


Figure 7-8 Cost development COGS / CMPA peers vs average 2003-2006.

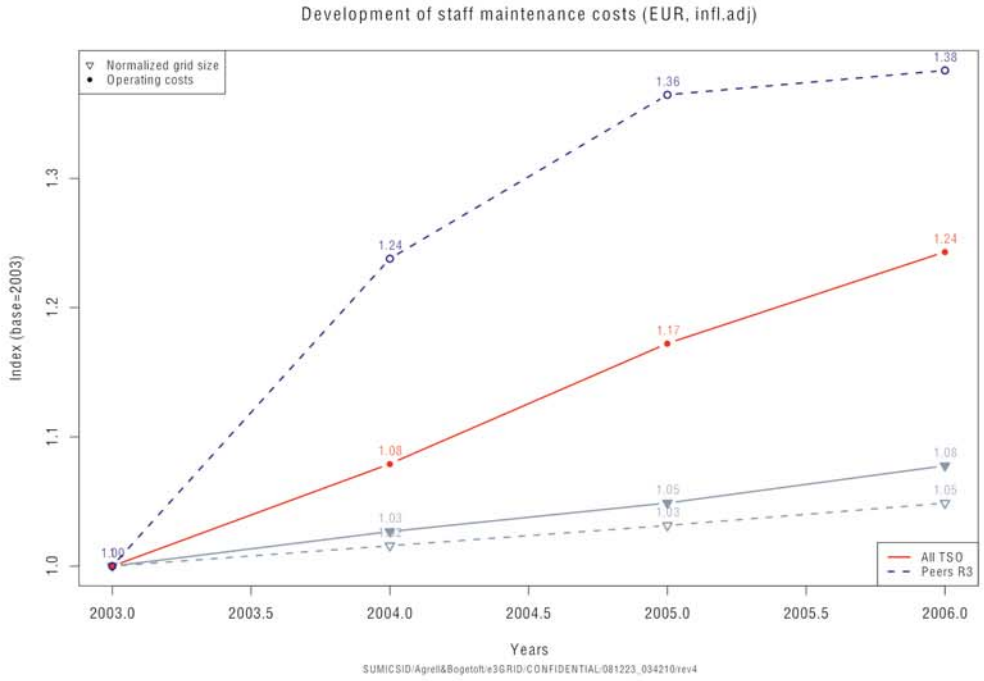


Figure 7-9 Cost development staff / M peers vs average 2003-2006.

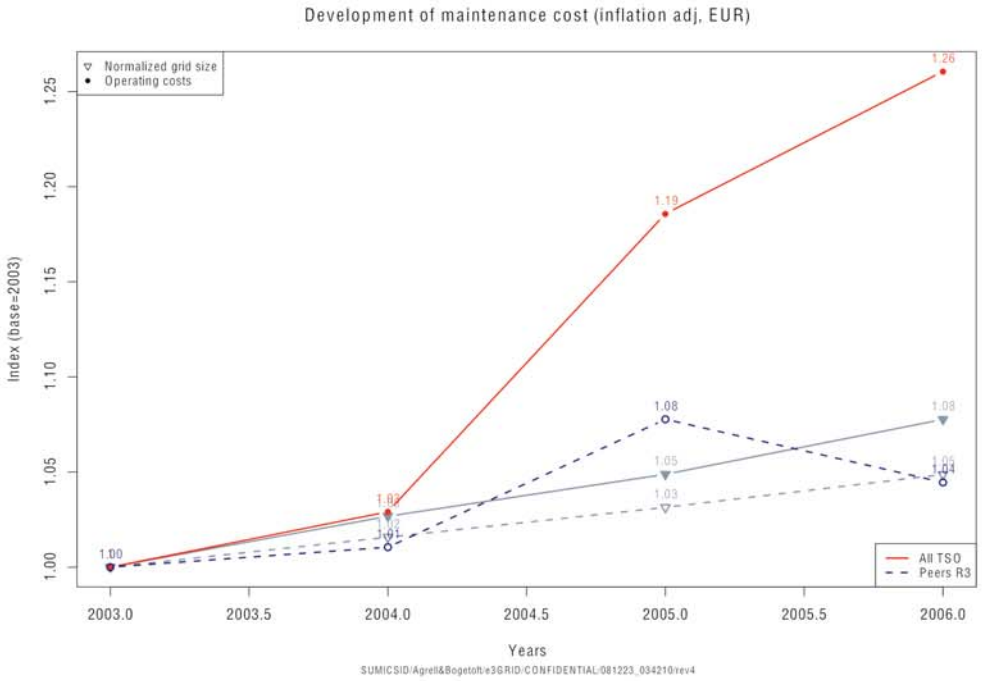


Figure 7-10 Cost development M peers vs average 2003-2006.

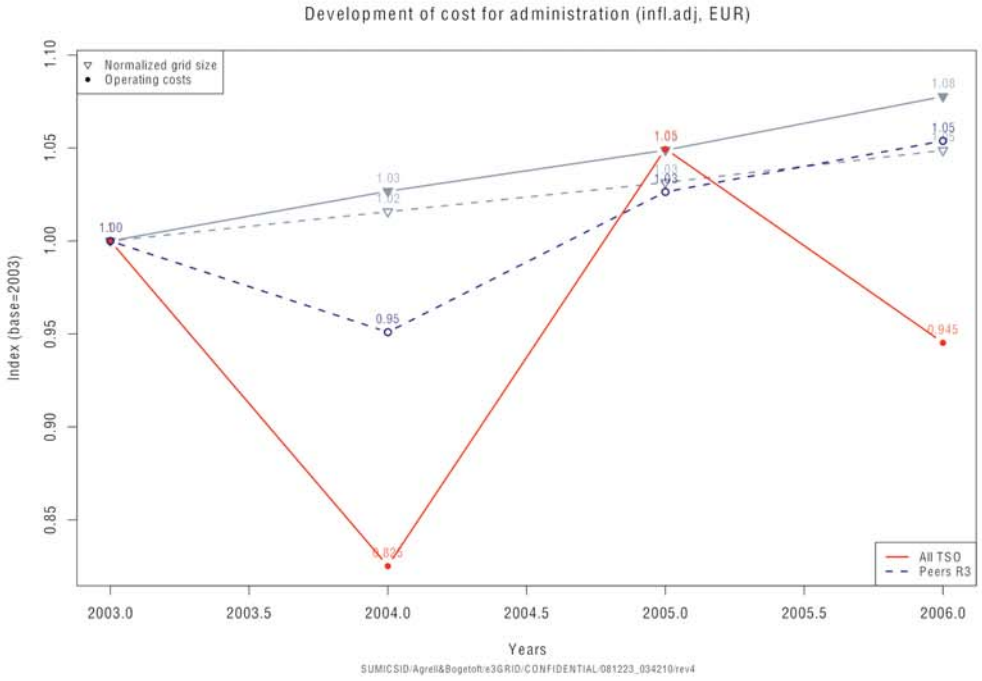


Figure 7-11 Cost development A peers vs average 2003-2006.

7.3 Regional differences in cost development

7.08 In the current study, we also distinguish different technologies between the Northern European (Nordic) operational standard (cable-stayed and wooden towers, transport grids, lower population density) and the Continental standard (steeltowers, higher population density, meshed grids). We have also performed an analogous analysis for Eastern European grids in order to investigate different drivers of performance. For reasons of confidentiality, this part of the analysis is not documented in the report.

7.4 Scope

7.09 In investigations of the possible scope for the frontier model, regressions have been made in order to determine common cost drivers for both asset-based functions (C, M, P) and operations-based functions (X and S). However, both statistical results and conceptual reasons (controllability of variables, assumptions about the comparability of factor markets, service heterogeneity) lead to the conclusion that the operations-based functions cannot be included in a common frontier model without making assumptions that might not be compliant with the cautiousness principle adopted initially.

7.10 However, average cost models and unit cost variance analysis (see Figure 7-12) indicate that an expansion of the scope to encompass operating costs for construction, maintenance, planning, support as well as capital expenditure (Totex CMPA) is advantageous. The extended scope does not increase the variance of the result and it eliminates the need for overhead allocation keys. Moreover, the extended scope also limits allocative inefficiency through assignment of resources to close functions (planning, support) in order to improve the score.

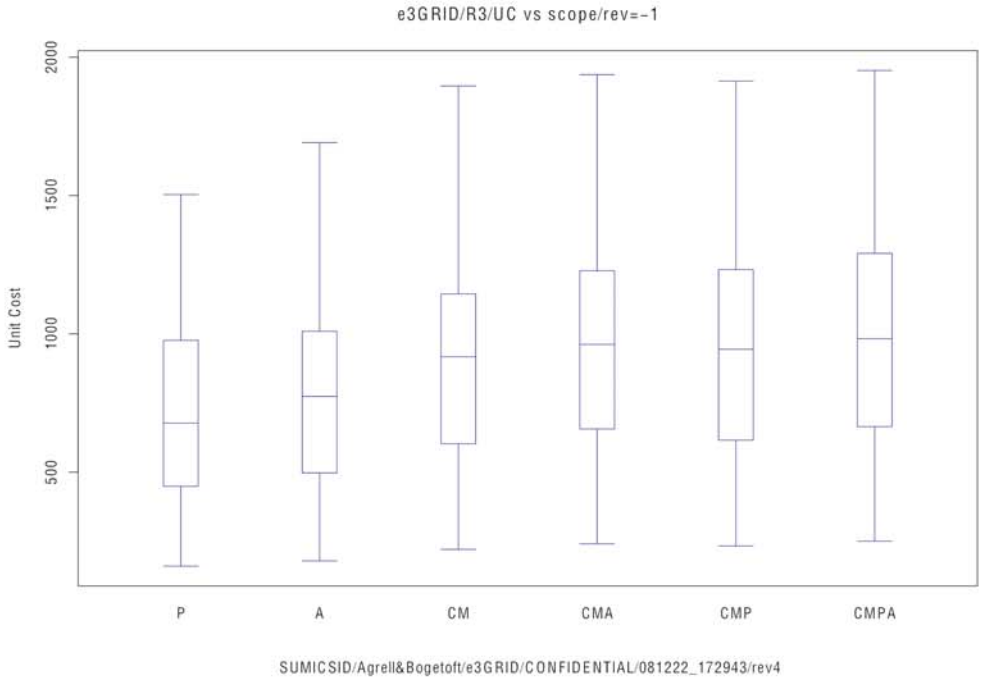


Figure 7-12 Example of unit cast analysis for mean and spread in determining scope.

7.5 Analysis of system operations costs

7.11 System operations costs constitute a major part of the operating budget for a transmission system operator. Thus, it would be unfortunate not to submit these costs to some performance assessment, like those for the asset-based functions CMPA. Based on the reasoning below, a complementary data collection was made in the project for system operations costs divided into eight predefined activities.

Activities (Call S)

7.12 Power system operations:

1) *Operations planning*
2) *Scheduling*
3) *Real time system monitoring and control*
4) *Coordination of system maintenance (safety)*

7.13 *Congestion management*. Costs and revenues resulting from the application of regulation EC 1228/2003 on cross-border exchanges. Cost item provided for consolidation.

7.14 *Balancing services (mechanisms)*. Costs and revenues accrued to the TSO for establishement of balance between generation and load, e.g. through

being residual claimant in a balance market based on bidding or delegating to balancing responsible parties.

7.15 *Ancillary services* (less balancing and energy losses)

1) *reactive power*
2) *power flow control (reactive and active)*
3) *frequency control*
4) *restoration of supply (black start, islanding)*

7.16 Power reserves

1) *Secondary power reserve (spinning reserve). Definition: the unused capacity which can be activated on decision of the system operator and which is provided by devices that are synchronized to the network and able to affect the active power. Corresponds to the UCTE secondary (automatic and central) and synchronized tertiary control reserves (manual and central). (Rebours, Hirschen, 2005). Excludes primary power reserve, see below.*
2) *Primary power reserve, defined as unused capacity provided by TSOs solidarily inside the UCTE area, activated within 30 seconds.*

7.17 Telecommunications

1) *Commercial ITC. Call C, art 5.18. Revenues from sale or rental of telecommunication services or assets to third parties (not included in basic access tariffs), costs resulting from the depreciation, operation, leasing or staffing of such services or assets. E.g. costs and revenues for giving access on fiber cables to commercial telephone operators.*
Assets in this activity are counted as non-grid related.
2) *Operational ITC. Costs for telecommunication services internal to the TSO, used to operate, monitor and document the operations and state of the grid. (Note that this position will be reallocated to M). Assets in this activity are considered grid-related and should appear in the investment stream.*

7.18 *Services to other grids*. Any costs and revenues from services in S other than those listed above (please specify under comments) provided to other grids, generators or end users.

7.19 *Training*. Costs and revenues providing both internal and external services related to training or operators, including development of instruction material and software as well as acquisition and maintenance of training facilities

1) *Training activities (internal/external)*
2) *Simulators for training (assets, operations).*

7.20 *Other* (residual from reported cost in S)

Complementary data collection

7.21 Cost data (complementary decomposition of data already reported in Call C) and physical data along with some questions regarding legal services obligations and market organization for balancing and ancillary services were collected between 21/10/2008 – 07/11/2008 for a total of nine TSO

forming an unbalanced panel 2003-2006. No useful responses were given for physical and legal data. Below we summarize the cost data as unweighted averages per activity, cost type and year in Table 7-5. A graphical illustration for the one year is presented in Figure 7-13 below, and gross margins are given in Table 7-6 and profitability information in Table 7-7.

Table 7-5 Summary data Call S

2003	Revenues	Manpower	Goods&Services	Depr.non.grid	Depr.grid	Leasing	Indirect	Other	Total Costs	Total EUR.2006
Power_system_operations	96,972	3,621,919	98,458	56,826	1,188,370	-	2,643,083	1,860,659	9,469,315	9,372,344
Congestion_management	9,005,326	261,975	5,449,078	3,157	66,021	-	195,444	864,101	6,839,775 -	2,165,550
Balancing_services	77,520,945	226,268	-	-	-	-	181,015	70,398,294	70,805,577 -	6,715,367
Ancillary_services	5,387	412,821	2,488,076	3,157	66,021	-	316,120	311,957	3,598,152	3,592,765
Power_reserves_Primary	-	75,423	-	-	-	-	60,338	10,656,369	10,792,130	10,792,131
Power_reserves_Secondary	-	56,567	15,821,159	-	-	-	45,254	3,368,075	19,291,055	19,291,056
ITC_Commercial	2,871,146	188,557	-	-	1,153,593	-	150,846	165,643	1,658,639 -	1,212,506
ITC_Operational	717,787	245,124	-	-	705,253	-	196,099	-	1,146,476	428,691
Training	-	94,278	-	-	-	-	75,423	883,430	1,053,131	1,053,132
Other_services	-	56,567	-	-	-	-	45,254	-	101,821	101,822
Residual	93,347,626	1,345,266	115,624 -	0	19,012,731	-	1,254,973	588,417	22,317,010 -	71,030,614
Total(EUR.2006)	183,565,189	6,584,765	23,972,395	63,140	22,191,988	-	5,163,847	89,096,946	147,073,081 -	36,492,107

2004	Revenues	Manpower	Goods&Services	Depr.non.grid	Depr.grid	Leasing	Indirect	Other	Total Costs	Total EUR.2006
Power_system_operations	9,723	3,157,350	86,470	91,281	1,086,462	-	2,847,596	349,303	7,618,462	7,608,740
Congestion_management	6,876,636	240,814	3,154,995	5,071	60,359	-	210,524	299,339	3,971,102 -	2,905,533
Balancing_services	116,178,522	243,579	-	-	-	-	194,863	107,597,154	108,035,596 -	8,142,925
Ancillary_services	540	403,200	2,437,272	5,071	60,359	-	340,433	288,337	3,534,673	3,534,133
Power_reserves_Primary	-	81,193	-	-	-	-	64,954	7,580,208	7,726,356	7,726,357
Power_reserves_Secondary	-	60,895	15,501,643	-	-	-	48,716	3,850,614	19,461,867	19,461,868
ITC_Commercial	2,695,430	202,982	-	-	1,236,157	-	162,386	220,035	1,821,560 -	873,868
ITC_Operational	715,114	263,877	-	-	690,415	-	211,102	-	1,165,394	450,281
Training	-	101,491	-	-	-	-	81,193	880,140	1,062,824	1,062,825
Other_services	-	60,895	-	-	-	-	48,716	-	109,610	109,611
Residual	129,417,567	1,551,273	272,146	473	19,035,326	-	1,683,424	23,373,634	45,916,277 -	83,501,289
Total(EUR.2006)	255,893,532	6,367,548	21,452,526	101,896	22,169,078	-	5,893,907	144,438,766	200,423,721 -	55,469,810

2005	Revenues	Manpower	Goods&Services	Depr.non.grid	Depr.grid	Leasing	Indirect	Other	Total Costs	Total EUR.2006
Power_system_operations	1,042	2,043,072	2,736,294	2,226,853	17,631,679	-	1,190,234	173,758	26,001,889	26,000,848
Congestion_management	18,592,362	105,580	3,219,002	4,018	21,075	-	87,816	1,193,041	4,630,531 -	13,961,829
Balancing_services	116,687,666	310,029	94,759,639	22,500	-	-	80,327	44,270,460	139,442,956	22,755,291
Ancillary_services	58	207,340	3,879,708	2,740	21,075	-	141,367	147,572	4,399,803	4,399,746
Power_reserves_Primary	-	43,236	2,980,818	658	-	-	26,776	1,935,152	4,986,640	4,986,641
Power_reserves_Secondary	1,243,249	145,653	44,331,669	8,125	-	-	20,082	2,611,698	47,117,226	45,873,978
ITC_Commercial	1,160,925	83,674	45,490	-	494,050	-	66,939	65,713	755,867 -	405,058
ITC_Operational	284,755	200,585	1,206,367	-	300,263	-	87,021	-	1,794,236	1,509,482
Training	-	50,124	1,554	-	-	-	33,470	306,659	391,807	391,808
Other_services	-	25,102	-	-	-	-	20,082	-	45,184	45,185
Residual	56,452,583	664,399	1,296,062	20	7,837,890	-	825,826	8,360,230	18,984,427 -	37,468,155
Total(EUR.2006)	194,422,640	3,878,794	154,456,601	2,264,914	26,306,034	-	2,579,939	59,064,283	248,550,566	54,127,927

2006	Revenues	Manpower	Goods&Services	Depr.non.grid	Depr.grid	Leasing	Indirect	Other	Total Costs	Total EUR.2006
Power_system_operations	4,143,346	5,992,039	2,654,269	1,222,550	10,079,495	240	825,619	3,044,144	23,818,355	19,675,010
Congestion_management	43,347,866	162,047	3,232,631	2,072	11,229	-	4,359,986	775,133	8,543,097 -	34,804,768
Balancing_services	110,665,628	321,700	67,890,485	12,386	2	-	42,817	50,302,158	118,569,548	7,903,921
Ancillary_services	850	158,207	8,091,458	1,515	11,228	-	76,654	237,041	8,576,103	8,575,254
Power_reserves_Primary	118	34,748	11,562,903	289	-	-	14,272	2,284,953	13,897,165	13,897,048
Power_reserves_Secondary	351,980	176,616	94,879,834	3,829	-	-	10,704	1,345,740	96,416,723	96,064,743
ITC_Commercial	14,096,888	1,164,101	5,849,598	-	2,173,103	6,739	208,815	627,030	10,029,385 -	4,067,502
ITC_Operational	200,719	146,786	1,207,463	-	972,898	-	46,385	95,640	2,469,173	2,268,455
Training	172	47,299	1,027	-	-	-	17,841	277,878	344,044	343,873
Other_services	-	13,380	-	-	-	-	10,704	-	24,085	24,086
Residual	47,058,164	855,877	15,992,967	72,148	5,410,274	469	812,326	5,919,820	29,063,881 -	17,994,282
Total(EUR.2006)	219,865,732	9,072,800	211,362,635	1,314,789	18,658,228	7,448	6,426,123	64,909,536	311,751,560	91,885,839

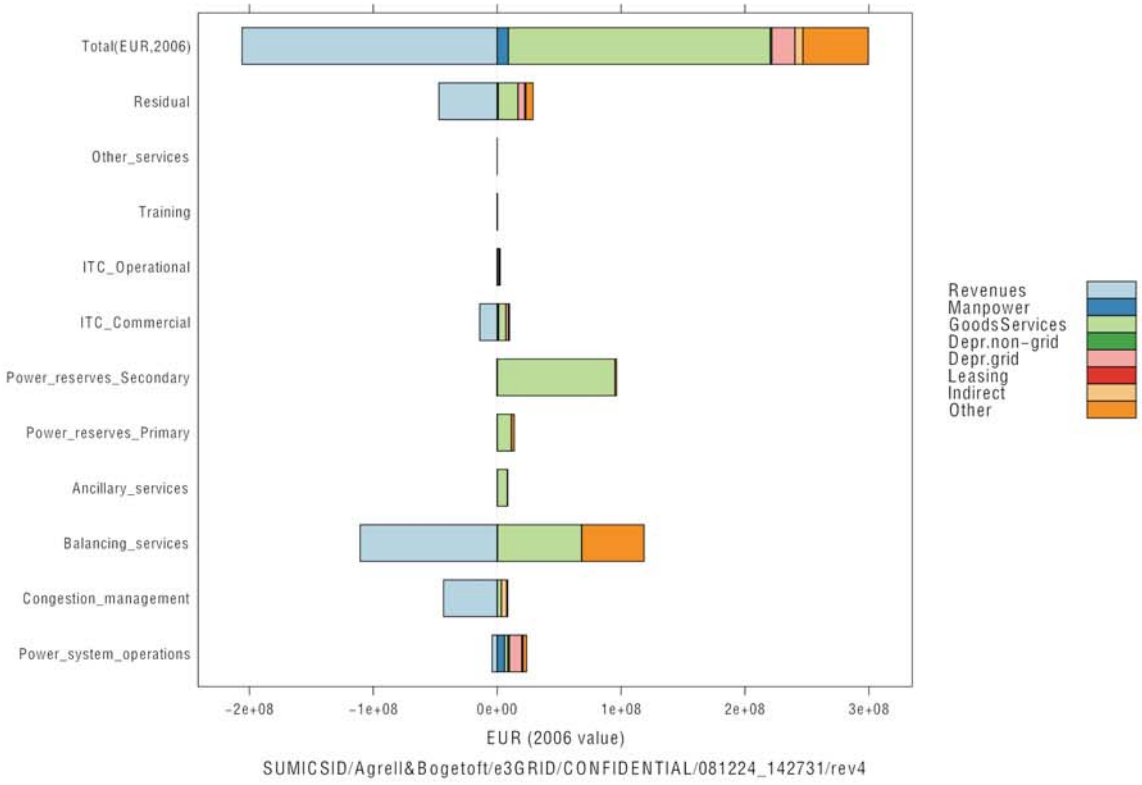


Figure 7-13 Average cost and revenues, system operations (partial sample), 2006, (EUR 2006)

Table 7-6 Gross margins (partial sample) system operations 2003-2006.

Gross margins	2003	2004	2005	2006
Power_system_operations	-98.8%	-99.8%	-100.0%	-66.9%
Congestion_management	33.0%	76.1%	303.7%	408.2%
Balancing_services	9.5%	7.5%	-16.3%	-6.7%
Ancillary_services	-99.8%	-100.0%	-100.0%	-100.0%
Power_reserves_Primary	-100.0%	-100.0%	-100.0%	-100.0%
Power_reserves_Secondary	-100.0%	-100.0%	-97.4%	-99.6%
ITC_Commercial	468.5%	360.4%	343.4%	79.4%
ITC_Operational	62.7%	50.6%	-80.9%	-86.6%
Training	-100.0%	-100.0%	-100.0%	-99.9%
Other_services	-100.0%	-100.0%	-100.0%	-100.0%
Residual	2725.1%	381.5%	406.5%	99.6%
Total(EUR,2006)	47.1%	43.6%	-11.6%	-29.4%

Table 7-7 Profitability (partial sample) system operations, 2003-2006.

Net margin 2003	2004	2005	2006
Power_system_operations	-99.0%	-99.9%	-100.0%	-82.6%
Congestion_management	31.7%	73.2%	301.5%	407.4%
Balancing_services	9.5%	7.5%	-16.3%	-6.7%
Ancillary_services	-99.9%	-100.0%	-100.0%	-100.0%
Power_reserves_Primary	-100.0%	-100.0%	-100.0%	-100.0%
Power_reserves_Secondary	-100.0%	-100.0%	-97.4%	-99.6%
ITC_Commercial	73.1%	48.0%	53.6%	40.6%
ITC_Operational	-37.4%	-38.6%	-84.1%	-91.9%
Training	-100.0%	-100.0%	-100.0%	-99.9%
Other_services	-100.0%	-100.0%	-100.0%	-100.0%
Residual	318.3%	181.9%	197.4%	61.9%
Total(EUR,2006)	24.8%	27.7%	-21.8%	-33.9%

Conclusion

7.22 The partial sample for system operations is insufficient to permit in-depth conclusions, but the approach seems promising for Fisher analysis to analyse productivity development even in the presence of exogenous prices. It may also serve as useful information for setting regulatory targets for all or part of the system operations costs.

7.6 Analysis of market facilitation

7.23 The market facilitation function is defined in subsection 3.2 above as a service with two interfaces; the spot markets for electricity connected to the grid and the national generation pool of supported technologies (renewables, decentralized, district heating, wind, etc). However, the function also covers regulatory missions related to the administration of support programs as well as residual functions for captive consumers. An overview of the cost types 2003-2006 in constant EUR 2006 value but prior to any adjustment are given in Table 7-8 below. The cost shares of various cost types are provided in Table 7-9 and the average costs per reporting TSO are given in Table 7-10.

7.24 The activity reporting under market facilitation is relatively sparse, only 7 of the 17 reporting TSO in 2006 provided details for more than two activities. However, a partial analysis of costs for 2006 is provided in Table 7-11 below. We note that 75% of the gross cost can be explained by four activities, two of which are only found in a single TSO report each. Moreover, the estimation for network losses only contains 11 reports of 17, which leads to an understatement. The residual contains also some elements that normally should have been reported to system operations, such as ancillary services revenues and balancing market operations. The number of employees reported occupied in market facilitation is listed in

Table 7-8, an increase is noted along with the increase in turnover for the function.

7.25 Seen as a benchmarking candidate, the market facilitation function has poor properties. For a comparative procedure to be informative, the tasks must be relatively homogenous and controllable. Market facilitation currently suffers from violations of the two conditions. The national legislation impose different tasks, obligations and rights to the TSOs with respect to both market establishment and generation support. Whereas some countries such as Germany through the EEG and KWK acts channel an important support program to DER and CHP generation, most countries still operate fairly modest support through the TSOs. However, the initiatives for these energy policy programs are rarely taken by the operators who exercise only a limited leeway with respect to the procedures to put into place. Even tasks like metering and billing differ in their modus operandi between operators. Thus, the potential for incentivzing market facilitation is likely limited to the procurement of energy for covering network losses, as suggested in the supplementary data collection on system operations (Call S).

Table 7-8 Cost analysis market facilitation (function X), gross of revenue, in (EUR, 2006), no overhead or salary adjustments.

Reporting TSO	8	9	12	17
Staff (fte)	87.5	82	126.5	347.8
	2003	2004	2005	2006
Gross cost	396,940,035	837,995,259	2,061,505,978	3,582,244,574
direct manpower cost	6,917,550	9,880,161	11,927,651	42,028,418
direct cost of purchases of services and expensed goods	376,619,427	339,607,445	1,213,334,013	2,387,265,682
depreciation of non-grid-related assets	456,811	444,722	6,962,337	9,966,026
depreciation of grid-related assets	1,435,186	503,186	1,348,473	1,365,419
leasing fees	822	1,717	664	240,810,900
indirect cost and overhead	2,364,298	2,373,965	2,619,607	3,008,980
other costs	10,581,127	485,687,250	826,661,706	899,164,568
Total cost	398,375,221	838,498,445	2,062,854,451	3,583,609,993
- grid depr	- 1,435,186	- 503,186	- 1,348,473	- 1,365,419
Total cost exl grid depr	396,940,035	837,995,259	2,061,505,978	3,582,244,574
- Revenue	878,306,867	851,271,343	821,136,275	1,390,728,045
Net cost excl grid depr	-481,366,832	-13,276,084	1,240,369,703	2,191,516,529

Table 7-9 Cost shares relative to total cost for market facilitation (function X), gross of revenue, in (EUR, 2006), no overhead or salary adjustments.

Reporting TSO	8	9	12	17
	2003	2004	2005	2006
direct manpower cost	1.7%	1.2%	0.6%	1.2%
direct cost of purchases of services and expensed goods	94.5%	40.5%	58.8%	66.6%
depreciation of non-grid-related assets	0.1%	0.1%	0.3%	0.3%
depreciation of grid-related assets	0.4%	0.1%	0.1%	0.0%
leasing fees	0.0%	0.0%	0.0%	6.7%
indirect cost and overhead	0.6%	0.3%	0.1%	0.1%
other costs	2.7%	57.9%	40.1%	25.1%
Total cost	100.0%	100.0%	100.0%	100.0%
- grid depr	0.4%	0.1%	0.1%	0.0%
Total cost exl grid depr	99.6%	99.9%	99.9%	100.0%
Revenue	220.5%	101.5%	39.8%	38.8%
Net cost excl grid depr	-120.8%	-1.6%	60.1%	61.2%

Table 7-10 Average gross cost per reporting TSO for market facilitation (function X), gross of revenue, in (EUR, 2006), no overhead or salary adjustments.

Reporting TSO	8	9	12	17
	2003	2004	2005	2006
direct manpower cost	864,694	1,097,796	993,971	2,472,260
direct cost of purchases of services and expensed goods	47,077,428	37,734,161	101,111,168	140,427,393
depreciation of non-grid-related assets	57,101	49,414	580,195	586,237
depreciation of grid-related assets	179,398	55,910	112,373	80,319
leasing fees	103	191	55	14,165,347
indirect cost and overhead	295,537	263,774	218,301	176,999
other costs	1,322,641	53,965,250	68,888,476	52,892,033
Total cost	49,796,903	93,166,494	171,904,538	210,800,588
- grid depr	- 179,398	- 55,910	- 112,373	- 80,319
Total cost exl grid depr	49,617,504	93,110,584	171,792,165	210,720,269
- Revenue	109,788,358	94,585,705	68,428,023	81,807,532
Net cost excl grid depr	-60,170,854	-1,475,120	103,364,142	128,912,737

Table 7-11 Partial activity analysis of market facilitation costs, 2006, EUR.

EUR	2006
Gross cost	3,582,244,574
Stranded costs (1 TSO)	-905,192,055
Incentive costs (1 TSO)	-805,655,903
Support programs KWK, EEG, green certificates) (6 TSOs)	-547,580,574
Cost for energy covering network losses (11 TSOs)	-443,995,849
Subtotal	-2,702,424,381
Residual	879,820,193

7.7 Analysis of grid financing

Background

7.26 The grid owner F function for an electricity transmission system operator is defined as:

7.27 *The grid owner function is the function that ensures the long-term minimal cost financing of the network assets and its cash flows, including debt financing, floating bonds, equity management, general and centralized procurement policies, leasing arrangements for grid and non-grid assets, management of receivables and adequate provision for liabilities (suppliers, pensions, etc).*

7.28 The purely financial function F (all costs for staff and services are allocated to A), is a manner to identify and separate certain idiosyncratic costs related to the institutional, legal, regulatory and macro-economic conditions that govern the mode and scale of the grid ownership. These costs, that in an uncorrected Totex framework would contaminate the comparison with elements beyond structural comparability, are here subject to specific reporting and an open comparison. As a consequence, the purpose of this analysis is not to determine a coefficient of managerial efficiency with respect to the function, but to provide comprehensiveness and to inform NRAs and TSOs about the range of financial conditions that prevail. The specific performance indicators calculated below are not to be included in any of the econometric models developed in the study and the outcome is not recommended for use in any regulatory proceedings.

Data

7.29 The data is primarily collected from the AMADEUS database from *Bureau van Dijk Electronic Publishing*, with the exception of certain operators where published annual reports and, in a few cases, regulatory accounts are used. The status of the data is public with the exception of the regulatory accounts.

Indicators

7.30 The calculated indicators are derived from the annual report and the profit and loss accounts of the operators. For the purposes of this analysis, we use a selection of profitability ratios, operational ratios and structure ratios. In addition, data on credit ratings and calculated metrics on default risk have been added for 2006. Below, the formulae are presented; the results are presented in Table 7-12 through Table 7-15 below.

Profitability ratios

7.31 The profitability ratios provide various views on the accounting health of the firm, oriented either on the return on capital or the cash-flow.

7.32 Return on shareholders' equity (%) = Pre tax income / Shareholders' equity * 100

7.33 Return on capital employed (%) = (Pre tax income + Interest and dividend paid) / (Reserves + Shareholders' equity + Long term liabilities) * 100

7.34 Return on total assets (%) = Pre tax income / Total assets * 100

7.35 Cash Flow / Turnover (%) = (Cash flow/Operating revenue)*100

7.36 Profit margin (%) = Pre tax income / Sales * 100

7.37 Gross Margin (%) = (Gross profit/Operating revenue)*100

7.38 EBITDA Margin (%) = (EBITDA/Operating revenue)*100

7.39 EBIT Margin (%) = (EBIT/Operating revenue)*100

EBITDA = Earnings before Interest, Taxes, Depreciation and Amortization

EBIT = Earnings before Interest and Taxes

Operational ratios

7.40 The operational ratios are turnover measures indicating the speed by which sales, debts and accounts receivables are transformed in the firm. In

particular, we focus the attention on a selected set of items related to the debt financing of the firm.

7.41 Net Assets Turnover = Sales / (Reserves + Shareholders' equity + Long term liabilities)

7.42 Interest cover = Operating profit / Interest and dividend paid

7.43 Collection period (days) = Debtors / Sales * 360

7.44 Credit period (days) = Creditors / Sales * 360

Structure ratios

7.45 The structure ratios (or solvency metrics) indicate to what extent the firm relies on internal resources to warrant for its external financing.

7.46 Current ratio = Current assets / Current liabilities

7.47 Liquidity ratio = (Current assets – Inventories) / Current liabilities

7.48 Shareholders' liquidity ratio = (Reserves + Shareholders' equity) / Long term liabilities

7.49 Solvency ratio (%) = (Reserves + Shareholders' equity) / Total shareholders' equity & liabilities * 100

7.50 Gearing (%) = (Long term liabilities + Short term loans payable) / (Reserves + Shareholders' equity) * 100

Analysis F: Profitability ratios

7.51 The European TSOs are relatively highly leveraged, which means that the nominal profitability on equity has a long tail of high values. It is also characterized by a high share of fixed investments, which explains that the EBITDA margin is about 4-5 times higher than the return on total capital and about double the return on capital employed. As expected, the industry historically has been fully protected from the downside risk through cost-recovery regulation schemes. However, the values for the end of the period show also some negative returns and in general lower margins than during the earlier period.

Table 7-12 Financial indicators, annual reports 2006 (n.a. = not available).

	min	median	average	max	Cllow 0.95	Clhigh 0.95	# n. a.
Profit and Loss Accounts							
Depreciation	0	58.516	211.557	1.687.873	194.834	393.028	2
Interest paid	0	11.829	23.627	129.300	21.920	38.880	3
Profitability ratios							
Return on shareholders funds (%)	-8	16	38	220	36	62	0
Return on capital employed (%)	0	10	14	77	13	23	3
Return on total assets (%)	-2	5	6	18	6	9	0
Cash Flow/Turnover (%)	-3	26	22	65	21	30	3
Profit margin (%)	-8	10	16	64	15	24	0
Gross Margin (%)	-4	11	17	88	16	30	8
EBITDA Margin (%)	0	32	31	84	29	42	3
EBIT Margin (%)	-4	11	22	75	20	31	0
Operational ratios							
Net assets turnover (x)	0	0	2	23	2	4	0
Interest cover (x)	0	4	41	670	36	104	3
Collection period (days)	0	40	57	325	53	86	2
Credit period (days)	0	46	52	353	48	85	4
Structure ratios							
Current ratio (x)	0	1	2	26	2	4	0
Liquidity ratio (x)	0	1	2	26	2	4	0
Shareholders liquidity ratio (x)	0	1	1	7	1	2	1
Solvency ratio (%)	5	28	32	81	30	40	0
Gearing (%)	0	172	302	1.681	281	468	0
Firm							
Company ratings	B	BB	BBB	A	-	-	5
Probability of default	0%	1,49%	1,92%	7,06%	1,88%	2,93%	1
Confidence level	0%	100,00%	76,29%	100,00%	75,71%	94,18%	1
Credit ratings							
Ratings (meanvalue)	B	BB	BBB	BBB	-	-	5
Probability of default	0%	1,99%	1,70%	3,48%	1,68%	2,31%	1
Average cost of debt	0%	3,21%	2,81%	8,77%	2,78%	3,93%	4

Table 7-13 Financial indicators, annual reports 2005.

	min	median	average	max	CIlow 0.95	CIhigh 0.95	# n.a.
Profit and Loss Accounts							
Depreciation	0	38.713	162.116	1.835.479	155.783	360.071	5
Interest paid	0	14.899	33.674	258.965	32.678	64.788	5
Profitability ratios							
Return on shareholders funds (%)	0	17	67	368	65	126	2
Return on capital employed (%)	0	10	12	80	11	20	5
Return on total assets (%)	0	7	6	20	6	9	3
Cash Flow/Turnover (%)	0	6	8	53	8	14	6
Profit margin (%)	0	16	17	62	17	26	4
Gross Margin (%)	0	26	21	100	20	36	8
EBITDA Margin (%)	0	24	20	87	19	32	6
EBIT Margin (%)	0	18	22	73	22	34	4
Operational ratios							
Net assets turnover (x)	0	1	1	3	1	1	3
Interest cover (x)	0	3	25	431	24	69	4
Collection period (days)	0	39	44	253	43	71	5
Credit period (days)	0	26	47	340	46	85	6
Structure ratios							
Current ratio (x)	0	1	1	2	1	1	2
Liquidity ratio (x)	0	1	1	2	1	1	2
Shareholders liquidity ratio (x)	0	1	1	7	1	2	3
Solvency ratio (%)	0	20	21	76	21	31	2
Gearing (%)	0	129	416	3.617	403	805	3

Analysis F: Operational ratios

7.52 The operational ratios show various observations. Besides the net asset turnover, that is too variable to permit any specific conclusions, the other measures suggests an increased cash turnover rate, in average also coupled with an improved self-financing through the ratio of operating profits to cash cost of equity (dividends) and debt. The credit and collection periods are stable and correspond to sector averages, given that the operators have mostly large (and often regulated) firms as customers.

Table 7-14 Financial indicators, annual reports 2004.

Profit and Loss Accounts	min	median	average	max	Cllow 0.95	Clhigh 0.95	# n.a.
Depreciation	0	10.550	126.232	1.822.613	119.547	335.168	7
Interest paid	0	7.700	27.356	204.546	26.447	55.759	6
Profitability ratios							
Return on shareholders funds (%)	-311	19	44	634	40	146	4
Return on capital employed (%)	0	15	18	123	17	33	6
Return on total assets (%)	0	8	5	15	5	8	5
Cash Flow/Turnover (%)	0	7	9	43	9	16	7
Profit margin (%)	0	19	15	49	15	23	6
Gross Margin (%)	0	20	16	92	15	29	8
EBITDA Margin (%)	0	48	24	85	24	38	8
EBIT Margin (%)	0	33	20	64	20	32	6
Operational ratios							
Net assets turnover (x)	0	1	8	101	7	22	5
Interest cover (x)	0	3	13	185	12	34	5
Collection period (days)	0	40	36	149	35	58	5
Credit period (days)	0	46	37	227	36	64	7
Structure ratios							
Current ratio (x)	0	1	1	5	1	2	5
Liquidity ratio (x)	0	1	1	5	1	1	5
Shareholders liquidity ratio (x)	0	0	1	6	1	1	6
Solvency ratio (%)	-4	12	20	100	20	35	4
Gearing (%)	-2.5	43	126	3081	111	605	4

Analysis F: Structure ratios

7.53 The current ratio is initially lower than expected for utilities (about 1.0), later under the period the ratio is improved, meaning that firms do not have to rely on long-term or supplier financing to settle cash-flow variations. The increase in the solvency ratio (from a rather low level) indicates in average a lowered leverage, normally suggesting that the relative cost of debt to equity would have been decreasing during the period. However, since the initial leverage may not have been sustainable with respect to the future expected variability in the returns, the adjustment may be driven by risk rather than capital costs.

Table 7-15 Financial indicators, annual reports 2003.

Profit and Loss Accounts	min	median	average	max	CIlow 0.95	CIhigh 0.95	# n.a.
Depreciation	0	12.500	148.456	1.855.279	140.776	388.510	4
Interest paid	0	11.900	28.825	195.497	27.868	58.758	6
Profitability ratios							
Return on shareholders funds (%)	0	15	74	706	71	188	5
Return on capital employed (%)	0	11	11	61	10	18	6
Return on total assets (%)	0	9	5	18	5	8	6
Cash Flow/Turnover (%)	0	8	10	48	10	18	6
Profit margin (%)	0	31	16	57	16	26	6
Gross Margin (%)	0	38	18	91	18	33	8
EBITDA Margin (%)	0	48	26	87	25	41	6
EBIT Margin (%)	0	37	21	64	21	34	6
Operational ratios							
Net assets turnover (x)	0	1	0	2	0	1	5
Interest cover (x)	0	2	2	17	2	5	5
Collection period (days)	0	38	49	459	47	108	6
Credit period (days)	0	60	43	324	42	86	7
Structure ratios							
Current ratio (x)	0	0	0	1	0	1	4
Liquidity ratio (x)	0	1	1	1	1	1	4
Shareholders liquidity ratio (x)	0	1	1	5	1	1	4
Solvency ratio (%)	0	15	18	76	18	31	4
Gearing (%)	0	111	205	1.211	200	376	4

7.54 Concerning the credit ratings we note a range between A and BBB corresponding to monotonically increasing default risks. Finally, the nominal average cost of debt is relatively low, a 95% confidence interval between 2.8% - 3.9%, which indicates real interest rates in the order of 2-3%, reflecting the favorable credit rating.

7.8 Summing up

7.55 The cost mass for the European electricity transmission operators reflects a capital intensive industry with overall real costs for both capital and operating expenditure increasing faster than load and grid growth. The costs for construction, maintenance, planning and support are primarily driven by asset intensity and complexity, in its turn related to load growth and reinforcement.

7.56 The growing share of system operations costs reflects the economic consequences of the deregulated market, where congestion, ancillary and

balancing markets represent important revenue items and power reserves constitute high cost drivers for some TSOs. System operations costs show potential for benchmarking using activity decomposition and index number approaches, such as Fisher. However, the partial sample does not allow any general results in this report. For market facilitation costs, the analysis points at lower potential value of benchmarking, besides certain specific costs. The market facilitation costs are also increasing due to the prevalence of support programs for decentralized and renewable generation, CHP and green certificates. The two latter costs are not deemed sufficiently homogenous in terms of controllability and task definition as to be included in the frontier model.

7.57 Grid financing costs, finally, point at relatively low financial costs and low risk classes, but also lowered margins at the end of the period. It could be interesting to contrast these results with predictions from the normative cost of capital works made by and for regulators.

8. Benchmarking results

8.1 Model, estimation approach and sample

8.01 It is not possible to do benchmarking based solely on data. We need to make some assumptions as well. With few data we typically have to introduce more assumptions and also to be less precise in our predictions.

8.02 The assumptions not only concern the choice of parameters used to standardize costs and investment streams and to aggregate different grid assets as described in the previous chapter. Benchmarking require us to choose

- *Which model specification (costs and cost drivers) to focus on*
- *Which estimation technique to use (parametric versus non-parametric etc)*
- *Which sub-sample to use in the calibration of a given model specification using a specific benchmarking technique.*

8.03 That assumptions impact the results is not a particular aspect of this benchmarking exercise. This happens in any benchmarking study although the reporting may not always emphasize this. In this study, we shall take the opposite approach and be very explicit about it. Indeed a large part of the preliminary analyses reported here has been to investigate the variation in outcome that may results from the variation in the model, estimation approach and sample used.

8.04 The dependence on assumptions does not mean that the outcome is simply a matter of assumptions. Some assumptions are better than others. As explained in the Method chapter, for example, theory, statistical tests, outlier tests etc shall be used to guide the choice of relevant models, estimation technique and sub-sample.

Multiple criteria problem

8.05 The choice of a benchmarking model, for now the choice of cost drivers, estimation technique and sub-samples, is a multiple criteria problem. We typically want to accomplish many different things with the models and the different objectives may conflict such that trade-offs are necessary.

8.06 There is no single criterion by which to choose the best model in a regulatory context.

8.07 This holds from a purely scientific point of view. Truly, there are several (conflicting!) proposals in the literature for a single criterion to guide the

choice of models. In particular this is the case in linear models with normal noise, e.g. the Akaiki criterion. However, good scientific work will not rely on a single criterion. It will emphasize the sound use of statistical techniques on conceptually sound model specifications and taking into account the specific data generation process.

8.08 The need for multiple criteria is further emphasized by the intended use of the models in regulatory context. Different countries have different regulations and in some regulations it may even be prescribed which cost driver to focus on and which estimation technique to use. Such prescriptions may at times conflict with classical statistical procedures.

8.09 In general therefore it is best to look at modelling as a multiple criteria problem.

8.10 In our investigation of alternative model specifications, cf. below, we have stressed the following four groups of criteria, conceptual, statistical, intuitive and experience and regulatory and pragmatic.

Conceptual

8.11 It is important that the model makes conceptual sense both from a theoretical and a practical point of view. The interpretation shall be easy and the properties of the model shall be natural. This contributes to the acceptance of the model in the industry and provides a safeguard against spurious models developed by data mining and without much understanding of the industry. To be more precise, this has to do with the choice of outputs that shall be natural cost drivers and with functional forms for example that have the right return to scale and curvature properties – e.g. that it is more expensive to produce more than less.

Statistical

8.12 It is of course also important to disciple the search of a good model with classical statistical criteria. Basically, we seek a model that is not underspecified leaving important drivers of costs outside the model. Likewise we seek a model that is not overspecified and try to explain all variation by simply using all possible parameters for the given entities in the given year; if we do so we are likely going to create spurious relationships that would lead to very bad predictions of costs outside the data set that we have used for the estimation. We therefore seek models that do not leave a large unexplained variation, and models that have significant parameters of the right signs.

Intuition and experience

8.13 Intuition and experience is a less stringent but nevertheless very important safeguard against false model specifications and the over- or underuse of data to draw false conclusions. It is attractive that the models produce results that are not that different from the results one has found in other comparisons. Of course, in the usage of such criteria, one always runs the risk of mistakes – we may screen away extraordinary but true results (Type 1 error) and we may go for a more common set of results based on false models (Type 2 error). The criteria shall therefore be used with caution.

8.14 One aspect of this is that one will tend to be more confident in a specification of inputs and outputs that leads to comparable results in alternative estimation approaches, e.g. in the DEA and SFA model. The experimental basis of this is that when we have a bad model, SFA will see a lot of noise and therefore attribute the deviations from the frontier to noise rather than inefficiency. Efficiencies will therefore be high. DEA on the other hand does not distinguish noise and inefficiency so in a DEA estimation, the companies will look very inefficient. Therefore, too deviating levels of efficiency in the DEA and SFA estimations may be a sign that the model is not well-specified. However, it should be emphasized that the aim is not to generate the same results using a DEA and an SFA estimation. The aim is to find the right model. However, a reasonable correlation and a comparable level of efficiency between the DEA and SFA results is an indication that the model specification is reasonable. It therefore also becomes an indirect success criterion.

Regulatory and pragmatic

8.15 The regulatory and pragmatic criteria perspective again calls for conceptually sound, generally acceptable models as discussed above. Also, the model shall ideally be stable in the sense that it does not generate too fluctuating parameters or efficiency evaluations from one year to the next. Otherwise, the regulator will loose credibility and the companies will regard the benchmarking exercise with skepticism. Of course, one shall not choose a model simply to make the regulator's life easy, so it is important to remember that similar results is also a sign of a good model specification, cf. the intuitive criteria above. The regulatory perspective also comes into the application of the model. If the model is not good, a high powered incentive scheme for example would not be attractive since it would allocate too much risk on the firms.

The process

8.16 In summary, we choose a modeling approach according to scientific standard. The analysis process is based on the idea of estimating a

number of DEA, COLS and SFA models based on different models structures, i.e. functional forms and input-output combinations. These models were analyzed based on the above criteria.

8.17 It follows from the pursuit of the multiple criteria in the modeling that it will not be a simple linear process. Truly, there is a natural sequence in the stages of the modeling involving

- *Model specification using average models*
- *Dimensionality reduction*
- *Frontier model estimation*
- *Second stage analyses*

8.18 In reality however it is necessary to return to the same stage repeatedly.

8.19 To illustrate, we have found TSOs that seemed to bias the frontier estimations or that were deemed as outlier in the frontier estimation stage. In many cases, however, renewed data validation have shown that this was due to a reporting problem, which has then forced the previous stages to be repeated with updated data.

8.20 To give another illustration, the analyses using average models may show that certain variables are significant cost drivers and others are not. In the frontier modeling however, it may turn out that not all the proposed cost drivers really matter on the frontier, while some excluded variables may have an impact on the frontier. In such cases, we have to return to the average model specification stage and redo the analyses forcing the former variables out and the latter in and then look for systematic impact of the remaining variables.

8.21 To give a third example, we may find variables that are significant in the average model but not in the parametric frontier models. In that case we may also try to aggregate (dimensionality reduce) some of the variables and then redo the average and frontier model specification stages.

8.2 General findings

8.22 The TSO industry is complicated to benchmark in part because of the low number of comparators. Indeed, the collection of detailed data from the TSOs in this study is a major effort and to the best of our knowledge, e3GRID is the largest European collection of standardized data for this sector ever. Still, it only gives us data for a small number of TSOs, namely a total of 22, which is a small number compared to studies of for example DSOs. The consequence of this is that *only simple models make sense* from a statistical point of view. Indeed both the average and the frontier models

we have investigated suggest that we shall use 1-3 or possibly 4 cost drivers to explain costs.

8.23 Second, the low number of observations and the variation in terms of scale and scope imply that *outliers are a particularly delicate problem*. A single outlier can influence the evaluation of many TSOs in a simple model with few cost drivers. This holds in the non-parametric (DEA) as well as the parametric (SFA, COLS) approaches. Indeed, it seems that the latter approach is quite sensitive to the elimination of a few outliers since they can affect the curvature of the cost functions and hereby have quite an impact even globally. The non-parametric approach in general has the advantage that impacts are more local – however this is less so in models with few cost drivers – and caution is necessary in these approaches as well. As a consequence we have carefully used outlier detection techniques of the cautious type – specifically the "German" approach as defined in the Method chapter.

8.24 Thirdly, we have found that the estimation of SFA models is particularly difficult in this sample. The reason is that the variation in performance is too large and the sample is too small. This means that it is often impossible to separate noise and inefficiency using maximum likelihood estimation. Too much variation in the data is often left unexplained to estimate SFA models. The best parametric approximation is therefore in general similar that of a COLS approach. Indeed, in terms of functional form estimated, the COLS and SFA analyses we have undertaken give much the same parameter values – but different efficiencies of course since the former by definition allocate all deviation from to model to the inefficiency term.

8.3 Model specifications

8.25 In previous parts of the project and as documented in the interim reports R1 and R2, we have found four models that are doing well on the criteria outlined above. We have in all cases primarily focused on explaining the combination of Opex and Capex, i.e. the cost is Totex, but the cost drivers vary from one model type to another.

8.26 In Model 1, the only cost driver in the Totex Sized of Grid measure, NGTotex, that corresponds to the numerator in the UC ratio. This model is natural since the grid elements are natural drivers of both capital and operating expenditures. It is reassuring – not the least given the considerable effort involved in the collection of assets information and the aggregation of these using weights – to observe that NGTotex is the single most important and significant cost driver in all the models we have investigated. Also, the NGTotex models are natural to investigate since

they are the simplest possible relaxation of the unit cost approach. Parametric and non-parametric models with NGTotex as cost driver can relax the constant return to scale assumption that is implicit in the UC approach, cf. the Method chapter.

8.27 In Model 2, we extended the set of cost drivers with Density that is a measure of the service population per square kilometre of service area. Urban areas have higher density than rural area and analysis on unit cost reveals this a major cost-increasing factor since the installation of assets and the maintenance of these are more complicated in a densely populated area.

8.28 In Model 3, we included a third cost driver, namely a measure of net installed capacity of renewable generation including hydro in the service area. This is a cost driver that has been discussed intensively in the industry and society at large. The idea would be that more renewable energy means less control on the grid and therefore less opportunities to maintain and operate the grid cost efficiently. It may also act as a general proxy for installations and topology that is more complex than average, e.g. prevalence of off-shore wind parks or hydro generation in inaccessible areas. Another more direct impact is of course that the configuration of the grid assets may differ, but this is accounted for directly in the NGTotex measure since any installation is treated as a cost driver without any analysis of the relevance of the installed assets.

8.29 In Model 4, we included the number of steel towers as a cost driver. This is to reflect differences in the technology that may not be captured by our asset weights for lines. In addition, the variations in the number of towers per km lines can hereby be accounted for.

8.30 In this final stage of the project we have identified what we consider to be the best model. For this purpose, we have re-estimated the above model specifications on the final data.

8.31 In addition, and to ensure that we have indeed identified the best model using the available data, we have done extensive second stage analyses to test if any excluded variables should potentially have been included. As explained in the methodological chapter, second stage analyses are done by considering whether an excluded variable in a regression analysis seems to have a significant impact on efficiency scores. Second stage regressions analyses provide a valuable control of the model specification.

8.32 Second stage analyses suffer however from two problems. First, they consider only extensions of an existing model and we may be interested also to look for simplifications or modifications, where we keep some of the cost drivers, remove some, and add some new ones. Hence, second

stage analyses provide a good check that we have not left out relevant information but they are less effective in identifying possible simplifications or alterations of a base model. Moreover, a regression based second stage analysis actually tests if the costs function can be separated in the cost impact of the new variables and the cost impact of the original variables. To see this, assume that calculated efficiencies are indeed a linear function of some variable y*, and let the original cost drivers be y. We then have

$$E^i = C(y^i)/C^i = a + by^{*i}$$

which would suggest that costs are really given by

$$(a + by^*)^{-1} C(y).$$

8.33 Hence what a linear or non-linear regression is testing is a particular form of the cost function that implicitly presumes separability of the impact of the original and the new cost drivers. In principle, we can therefore have situations where the second stage analysis is not flagging the relevance of a cost driver.

8.34 In addition to extensive second stage analyses, we have therefore directly examined the usefulness of the alternative cost driver specifications. We have done this by examining 125 alternative specifications using 1, 2, 3 or 4 cost drivers from the set of available possible cost drivers.

8.35 The analyses of this last set of alternative specifications serve to ensure that we have not only picked a conceptually sound model, but also a model that is superior from a statistical point of view.

8.36 To get a general measure of the statistical goodness of fit of a model, we have used the sums of squared inefficiencies across the scores. Formally, the deviation measure can be expressed as

$$D(M) = \sum_{i=1}^{n} (1 - E(M)^i)^2$$

8.37 In this formula, n is the number of TSOs and $E(M)^i$ is the cost inefficiency of TSO^i when evaluated in the model M. Clearly, small values of D are an indication that the model M provides a good fit in the sense that the TSOs in general are evaluated to be close to fully efficient, which is the natural base hypothesis.

8.38 In general we would expect the deviation to fall when we extend a model with additional cost drivers. This would suggest a correction for the number d(M) of cost drivers in the model M, e.g. as in

$$\frac{1}{n - d(m)} \sum_{i=1}^{n} (1 - E(M)^i)^2$$

8.39 This measure can be interpreted as an estimate of the variance of the efficiency around 1 corresponding to full efficiency.

8.40 To statistically compare two models with a different numbers of cost drivers, one can then use the ratio of the corresponding deviation measures. Thus for example, if M_0 and M_1 are compared, we could calculate

$$Q(M_1, M_0) = \frac{D(M_1)/(n - d(M_1)}{D(M_0)/(n - d(M_0)}$$

8.41 Small value of this indicator would be favourable to M_1 while large value would favour M_0.

8.42 Under more stringent assumptions, and with a sufficiently large data set, this approach can be turned into a statistical significance test, cf. e.g. Banker (1996). Given our limited number of observations, we are not able to statistically test if a better fit is really statistically significant. Moreover, our situation is complicated by the interaction with the outlier detection criteria, which means than we cannot even guarantee increasing average efficiency with increasing number of cost drivers. Therefore, there will be a tendency to have decreasing deviations when the number of cost drivers increases, but it may not hold when the set of outliers is affected.

8.43 Even if we cannot derive the distributional assumptions and hereby formally test if one model is superior to another by the deviation or the corrected deviation measures, we can still use them as an indication of the goodness of fit.

8.4 Static results

8.44 Below we present the static results for the combinations of the CMPA scopes.

Unit cost results

8.45 The unit costs evaluations based on the final data are given in Table 8-1 below. The unit costs are calculated using Totex, Opex, Capex and Adjusted Totex, respectively. Moreover, we give the unit costs evaluations both before and after the elimination of outliers. To determine if one or more units are outliers, we use the two outlier detection criteria defined in 4.68. That is, a unit is an outlier if it outperforms the others to an extreme degree or if it has a large impact on the evaluation of a large number of

units. We see that there are two outliers in the UCTotex distribution. When they are eliminated, the effect is that average efficiency is increased from 0.32 to 0.64.

Table 8-1 Unit cost efficiencies (UC)

UC scores *Scope* *Reference set*	Totex ALL	Totex ex out	Opex ALL	Opex ex out	Capex ALL	Capex ex out	Adjtot ALL	Adjtot ex out
Average	0.32	0.64	0.41	0.52	0.31	0.51	0.41	0.53
St.Dev	0.21	0.26	0.25	0.26	0.22	0.26	0.22	0.26
Max	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
Min	0.13	0.29	0.07	0.14	0.10	0.19	0.11	0.14
Outliers		2		1		2		1

8.46 We consider the most relevant of these measures to be d_UCTotex_ex_out, i.e. the usual unit cost measures except that outliers have been eliminated, and UCAdjTotex_ex_out, i.e. the unit cost efficiency of the adjusted Totex after the elimination of outliers. The latter is, as we have explained, basically a measure of Opex efficiency taking into account the capital input since any possible inefficiency in investments has here been eliminated.

8.5 Model analysis

8.47 The unit cost efficiencies presume that cost depends on the size of grid only. Moreover, it assume a constant return to scale relationship such that increasing or decreasing the size of grid by a factor k will lead to a corresponding increase or decrease in costs. We now turn to more elaborate models along the lines of Model 1, 2, 3 and 4 introduced above.

Analyses of the possible models

8.48 To determine the appropriateness of a model and to verify that the identified model is indeed superior to available specifications, we have, as explained above, considered a series of cost model specifications. Specifically, we have considered models with 1, 2, 3 or 4 cost drivers from the different groups of potential cost drivers, viz. grid size, transported energy, power generation, tower types, service areas, and age.

8.49 A subset of the alternative specifications and the corresponding deviation measures are given in Table 8-2 below. Different models correspond to different lines. They are each characterized by the average efficiency

before and after the elimination of outliers in the first two columns. The next columns give the deviation measure defined above in the model before and after the exclusion of outliers. The latter goodness of fit measure, i.e. the D2 value in the table, has been used to sort the different models. We get the best fit in the first model, the second best fit in the second etc.

Table 8-2 Subset of alternative models with associated deviation measures

Av Eff dea.ndrs	Av Eff dea. ndrs.ex.out	Deviation D1	Deviation D2	Cost drivers			
0.52	0.86	6.56	1.00	yNGTotex	yService.pop	yPower.gen.ren.incl.hydro	yEnv.area.forest
0.52	0.86	6.48	1.02	yNGTotex	yService.pop	yPower.gen.hydro	yEnv.area.forest
0.53	0.86	6.26	1.03	yNGTotex	yService.pop	yPower.gen.ren.incl.hydro	yEnv.area
0.54	0.86	5.91	1.05	yNGTotex	yService.pop	yPower.gen.ren.incl.hydro	yEnv.area.agri
0.53	0.86	6.18	1.05	yNGTotex	yService.pop	yPower.gen.hydro	yEnv.area
0.55	0.86	5.86	1.07	yNGTotex	yService.pop	yPower.gen.hydro	yEnv.area.agri
0.43	0.87	8.60	1.10	yNGTotex	yDensity	yPower.gen.ren.incl.hydro	
0.51	0.84	6.92	1.26	yNGTotex	yService.pop	yPower.gen.nuclear	yEnv.area.forest
0.52	0.84	6.58	1.31	yNGTotex	yService.pop	yPower.gen.nuclear	yEnv.area
0.61	0.83	4.60	1.33	yNGTotex	zTowers.steel	yPower.gen.ren.incl.hydro	yDensity
0.70	0.84	3.22	1.44	yNGTotex	zTowers.steel	yPower.gen.wind	yDensity
0.59	0.82	5.36	1.47	yNGTotex	zTowers.steel	yPower.gen.ren.incl.hydro	yDensity
0.53	0.82	6.25	1.55	yNGTotex	yService.pop	yPower.gen.nuclear	yEnv.area.agri
0.41	0.82	8.17	1.62	yNGTotex	yDensity		
0.70	0.80	3.36	1.73	yNGTotex	zTowers.steel	yPower.gen.gas	yDensity
0.67	0.81	3.68	1.77	yNGTotex	zTowers.steel	yPower.gen.ren.excl.hydro	yDensity
0.66	0.78	3.54	1.96	yNGTotex	zTowers.steel	yPower.gen.nonren	yDensity
0.67	0.78	3.48	1.97	yNGTotex	zTowers.steel	yPower.gen.thermal	yDensity
0.61	0.77	4.59	1.98	yNGTotex	zTowers.steel	yPower.gen.hydro	yDensity
0.61	0.78	4.63	1.99	yNGTotex	zTowers.steel	yPower.gen.nuclear	yDensity
0.63	0.79	4.65	2.14	yNGTotex	yService.pop	yPower.gen.wind	yEnv.area.agri
0.61	0.78	4.84	2.24	yNGTotex	yService.pop	yPower.gen.wind	yEnv.area
0.60	0.77	5.16	2.33	yNGTotex	yService.pop	yPower.gen.wind	yEnv.area.forest
0.67	0.75	3.95	2.41	yNGTotex	zTowers.steel	yPower.gen.gas	zAge1
0.68	0.76	3.87	2.47	yNGTotex	zTowers.steel	yPower.gen.wind	zAge1
0.58	0.75	5.36	2.49	yNGTotex	yService.pop	yPower.gen.gas	yEnv.area
0.60	0.75	5.21	2.51	yNGTotex	zTowers.steel	yPower.gen.ren.incl.hydro	zAge1
0.56	0.75	5.68	2.55	yNGTotex	yService.pop	yPower.gen.thermal	yEnv.area.agri
0.60	0.75	5.03	2.56	yNGTotex	yService.pop	yPower.gen.gas	yEnv.area.agri
0.57	0.75	5.71	2.57	yNGTotex	yService.pop	yPower.gen.gas	yEnv.area.forest
0.69	0.74	3.54	2.65	yNGTotex	zTowers.steel	yPower.gen.gas	zAgem
0.65	0.73	4.07	2.68	yNGTotex	zTowers.steel	yPower.gen.thermal	zAge1
0.58	0.75	5.41	2.69	yNGTotex	yService.pop	yPower.gen.ren.excl.hydro	yEnv.area
0.60	0.74	5.19	2.69	yNGTotex	zTowers.steel	yPower.gen.hydro	zAge1
0.70	0.75	3.46	2.70	yNGTotex	zTowers.steel	yPower.gen.wind	zAgem
0.62	0.74	4.70	2.70	yNGTotex	zTowers.steel	yPower.gen.ren.incl.hydro	zAgem
0.56	0.73	5.66	2.71	yNGTotex	yService.pop	yPower.gen.nonren	yEnv.area.agri
0.64	0.72	4.14	2.73	yNGTotex	zTowers.steel	yPower.gen.nonren	zAge1
0.55	0.73	5.92	2.75	yNGTotex	yService.pop	yPower.gen.thermal	yEnv.area
0.60	0.74	5.01	2.77	yNGTotex	yService.pop	yPower.gen.ren.excl.hydro	yEnv.area.agri
0.66	0.72	3.71	2.77	yNGTotex	zTowers.steel	yPower.gen.nonren	zAgem
0.66	0.72	3.67	2.78	yNGTotex	zTowers.steel	yPower.gen.thermal	zAgem
0.53	0.72	6.27	2.82	yNGTotex	yService.pop	yPower.gen.thermal	yEnv.area.forest
0.55	0.71	5.93	2.91	yNGTotex	yService.pop	yPower.gen.nonren	yEnv.area
0.62	0.73	4.68	2.96	yNGTotex	zTowers.steel	yPower.gen.hydro	zAgem
0.54	0.71	6.27	2.98	yNGTotex	yService.pop	yPower.gen.nonren	yEnv.area.forest
0.64	0.72	4.37	3.02	yNGTotex	zTowers.steel	yPower.gen.ren.excl.hydro	zAge1
0.57	0.71	5.68	3.04	yNGTotex	yService.pop	yPower.gen.ren.excl.hydro	yEnv.area.forest
0.59	0.71	5.32	3.18	yNGTotex	zTowers.steel	yPower.gen.nuclear	zAge1
0.66	0.70	3.90	3.23	yNGTotex	zTowers.steel	yPower.gen.ren.excl.hydro	zAgem
0.61	0.70	4.78	3.24	yNGTotex	zTowers.steel	yPower.gen.nuclear	zAgem
0.53	0.69	7.21	4.31	yNGTotex	zTowers.steel	yPower.gen.ren.incl.hydro	
0.40	0.65	9.69	4.84	yNGTotex	yPower.gen.ren.incl.hydro		
0.39	0.63	9.88	4.98	yNGTotex	yPower.gen.hydro		
0.50	0.60	7.96	6.19	yNGTotex	zTowers.steel		
0.42	0.58	9.80	6.84	yNGTotex	yPower.gen.wind		
0.39	0.53	10.53	7.29	yNGTotex	yPower.gen.gas		
0.40	0.54	10.24	7.34	yNGTotex	yPower.gen.nuclear		
0.45	0.54	9.10	7.36	yNGTotex	yPower.gen.ren.excl.hydro		
0.39	0.52	10.32	7.42	yNGTotex	yPower.gen.thermal		
0.39	0.52	10.32	7.43	yNGTotex	yPower.gen.nonren		
0.36	0.49	10.90	8.07	yNGTotex			

8.50 We see that only very few models have lower deviation values than the first marked model which corresponds to Model 3 above. Moreover, the few models with lower deviation measure are all using more cost drivers

and the lower variance in performance is therefore not a sufficient argument to prefer these.

8.51 We have nevertheless examined these models more carefully. We see that they conceptually are similar to Model 3 except that the density measure is substituted by a population and an area measure. Moreover alternative measures of power generation seem to be close substitutes. (We see however that hydro related power measures seem to be favoured in general.)

8.52 Density is defined as the service population per service area, and is therefore declining in area. This suggests a possible conceptual difference to the models with lower deviation measure where area by construction is a positive cost driver. It turns out, however, that when a linear or log-linear parametric form of the first models is estimated, the area does indeed come out with a negative impact, i.e. costs seem to decline with area for a fixed population. In other words, in the models with lower deviation measure than model 3, we have both more cost drivers and we have a conceptual conflict between the DEA model, in which larger areas increase costs, and the parametric models, where larger areas decrease costs. To illustrate this, the log-linear estimate of the third model in Table 8-2 becomes

$$Totex = Exp\,(8.406) * NGTotex^{0.704} Ren^{0.051} Pop^{0.121} Area^{-0.096}$$

8.53 For these reasons, we consider Model 3 to be the most attractive of the models in Table 8-2.

8.54 The next highlighted model is Model 2 and the last one is Model 1. It is reassuring to see that even these models, identified in earlier stages of the project based on conceptual reasoning and preliminary data, are in fact doing rather well compared to models with more cost drivers.

8.55 We observe also that more variables do not necessarily lead to a better fit. This is the result of the outlier criteria that may identify more entities as outliers in a simplified model. This illustrates the trade-off in the modelling between elimination of some comparators via an outlier criterion and eliminating it via additional cost drivers.

Model 3 results

8.56 The best model specification is therefore to use Model 3, i.e. to have Totex as cost and NGTotex, Density and Renewable Power incl. hydro as cost drivers. Moreover, the best estimation technique given the limited data is to use the DEA-NDRS approach.

8.57 The average efficiencies of the different TSOs in this model are given in Table 8-3 below. There are three outliers in this specification. With the relatively large number of cost drivers compared to the sample size, a large number of TSOs become fully efficient and the average efficiency in the full sample of 22 TSO becomes 0.87 after the exclusion of the three outliers.

8.58 Table 8-3 also gives the scores for the AdjustedTotex measure using the same cost drivers. This provides an estimate of Opex efficiency where we have corrected for the usage of different amount of Capex.

Table 8-3 Best Model DEA-NDRS estimates of efficiency

Return to scale	NDRS	NDRS	NDRS	NDRS
Scope	Totex	Totex	AdjTotex	AdjTotex
Reference set	ALL	Ex out	ALL	Ex out
Average	0.43	0.87	0.55	0.71
St.Dev	0.25	0.19	0.27	0.28
Max	1.00	1.00	1.00	1.00
Min	0.16	0.38	0.13	0.27
Outliers		3		1

8.59 We see that by eliminating the three outliers identified by the super-efficiency criteria of the Method chapter, the average efficiency increases from 0.42 to 0.87 in the Best Model using the Totex. Hence, the three outliers have a considerable impact on the performance standards. Qualitative analyses of the contextual conditions of the three outliers confirm that they most likely benefit from special circumstances and technology, and that these factors may not easily be imitated by other TSOs. This is not to say that all of the cost savings in these TSOs are due to special structural and technological conditions. Indeed, there is evidence to suggest that they are in fact efficiently managed. However, since it is difficult to separate the structural impact from the management impact, we recommend a cautious approach and to evaluate the others against a frontier that does not depend on the outliers.

8.60 The consequence of this choice is that 12 of the 22 TSOs in the study are classified as fully efficient in the Totex analyses.

8.61 A similar analyses performed on Adjusted Totex modifies this conclusion. Some of the fully efficient TSOs are benefitting from high investment efficiency and may therefore in reality be able to improve on Opex even though they are efficient in the Totex model. Table 8-3 above documented this. We see that 6 of the 12 Totex efficient TSOs are inefficient in Opex in

the sense that when we neutralize differences in (historical) investment efficiency, they are no longer fully efficient.

Alternative estimation methods

8.62 We have of course also estimated efficiencies using alternative parametric and the non-parametric models from the Method chapter. The correlations of the results of different estimation approaches are reasonable when it comes to the best model estimated with DEA-NDRS. In general, the parametric approaches, however, correlate better with the UC evaluations. This is not surprising since the parametric approaches have less flexibility in the relationship between cost drivers and costs, i.e. we would expect a close relationship to the simple unit cost efficiencies – also since these methods are rather sensitive to outliers. The convergence of the SFA models is very unstable. This reflects that too much variation is left unexplained in data to estimate a parametric SFA model, i.e. it is largely impossible to separate noise and inefficiency using maximum likelihood estimation. We have too large variation in a small sample. In general however the COLS and SFA approaches give the same structure – but different efficiency levels of course.

8.63 A few selected correlations are shown in Table 8-4 below.

Table 8-4 Correlation between different estimation methods

PEARSON	d_uctotex	d_ucopex	d_uccapex	d_uctotexadj	d_fdh	d_dea_ndrs	d_dea_ndrs_ex_out	d_dea_ndrs_biascorr	d_dea_ndrs_biascorr_c1	d_dea_ndrs_biascorr_c2	d_colslog	d_sfa_loglinear	d_sfa_normedlinear_vrs
d_uctotex	1.00	0.80	0.97	0.82	0.22	0.77	0.44	0.85	0.84	0.76	0.86	0.80	0.49
d_ucopex	0.80	1.00	0.65	0.98	0.33	0.63	0.43	0.70	0.69	0.63	0.67	0.65	0.26
d_uccapex	0.97	0.65	1.00	0.68	0.13	0.72	0.40	0.80	0.79	0.71	0.84	0.78	0.52
d_uctotexadj	0.82	0.98	0.68	1.00	0.36	0.60	0.47	0.68	0.67	0.59	0.67	0.66	0.25
d_fdh	0.22	0.33	0.13	0.36	1.00	0.25	0.48	0.27	0.26	0.26	0.22	0.23	0.12
d_dea_ndrs	0.77	0.63	0.72	0.60	0.25	1.00	0.53	0.99	0.99	1.00	0.92	0.85	0.60
d_dea_ndrs_ex_out	0.44	0.43	0.40	0.47	0.48	0.53	1.00	0.55	0.55	0.55	0.54	0.64	0.46
d_dea_ndrs_biascorr	0.85	0.70	0.80	0.68	0.27	0.99	0.55	1.00	1.00	0.99	0.95	0.88	0.61
d_dea_ndrs_biascorr_c1	0.84	0.69	0.79	0.67	0.26	0.99	0.55	1.00	1.00	0.99	0.95	0.88	0.61
d_dea_ndrs_biascorr_c2	0.76	0.63	0.71	0.59	0.26	1.00	0.55	0.99	0.99	1.00	0.92	0.85	0.60
d_colslog_far	0.86	0.67	0.84	0.67	0.22	0.92	0.54	0.95	0.95	0.92	1.00	0.96	0.56
d_sfa_loglinear_far	0.80	0.65	0.78	0.66	0.23	0.85	0.64	0.88	0.88	0.85	0.96	1.00	0.53
d_sfa_normedlinear_vrs_far	0.49	0.26	0.52	0.25	0.12	0.60	0.46	0.61	0.61	0.60	0.56	0.53	1.00

8.64 The parametric form of Model 3 is however interesting. The loglinear estimation is given by

$$Totex = Exp\,(8.4123183)*NGTotex^{0.733}Density^{0.099}Ren^{0.04}$$

8.65 We see that costs are increasing in grid, density and renewable power, but the marginal increase is declining corresponding to *positive economies of scale* in all the variables.

Bias correction

8.66 In theory, DEA models provide cautious estimates of the saving potentials and cost inefficiencies. This is due to the minimal extrapolation principle that is used to estimate the cost function from actual observations, and it presumes of course that the underlying theoretical conditions are valid and in particular that deviation from best practice is the result of inefficiency and not noise.

8.67 To evaluate the robustness of our results, we have also estimated absolute efficiency estimates and confidence intervals for these. We have done so using the bootstrapping technique described in Chapter 4. Although we do these calculations here to gauge the robustness of the relative efficiency estimates of Model 3 in art 8.56, we note that in some regulations, it may actually be reasonable to use the latter – or the upper confidence interval for the absolute efficiency level in the regulation, cf. the discussion in art 4.105. Which of the measure to use depend in part on the risk the regulator is willing to take – the absolute efficiency makes it more likely that the resulting revenue cap may not be individually rational for the TSO and the use of the upper confidence value limits this risk

8.68 We have investigated the bias corrected efficiencies as well of the associated confidence 95% confidence intervals. We see that the bias correction shifts the estimated cost efficiencies down and that in particular the fully efficient units get quite considerable bias corrections. This is due to the fact that we only have a relatively small sample of TSOs compared to the number of cost drivers that we use. TSOs may in such a setting get rather high scores simply because there are rather few possible comparators.

8.69 Another illustration of the robustness is to compare the outcomes under non-decreasing return to scale, NDRS, and cost return to scale, CRS. In theory, and when the set of outliers is not altered, the CRS efficiencies can never be higher than the NDRS, and they will tend to be lower if there are large TSOs that are very efficient since they can now be scaled down to dominate small TSOs. We see that in fact the impact is limited – only three TSOs are affected and only one of them is facing a large drop in efficiency.

Second stage analyses

8.70 The analyses of a large number of alternative model specifications services to validate the preferred model 3. In particular, we analyzed both simplifications of Model 3 and a series of alternatives using 3 or 4 cost drivers.

8.71 It is good practice, however, to always investigate a final model by so-called second stage analyses. As explained, the idea of second stage analyses is to investigate if some of the remaining variation in performance can be explained by any of the unused potential cost drivers. This is routinely done by regressing the efficiency scores on these variables in turn. The result of such an exercise is given in Table 8-5 and Table 8-6 below. Large value of the F test statistic would be an indication that it could be useful to include the variable in question in the model. We see that only two variables are significant at the 5% level, namely yPower.gen.gas and yEnv.area.roads.

Table 8-5 Second stage analyses (1)

Regressor	Df	F value	Pr(>F)
yNGOpex	1	0.11	0.74
yNGCapex	1	0.03	0.86
yNGTotex	1	0.05	0.82
yEnergy.del	1	0.38	0.55
yEnergy.del.res	1	0.10	0.75
yEnergy.del.com	1	0.68	0.42
yEnergy.del.ind	1	0.65	0.43
yEnergy.losses.transm	1	3.80	0.10
yEnergy.losses.distr	1	0.06	0.81
yEnergy.import	1	0.14	0.71
yEnergy.export	1	1.60	0.22
yEnergy.gen.ren	1	3.34	0.09
yEnergy.gen.hydro	1	0.08	0.79
yEnergy.gen.CHP	1	0.16	0.70
yPower.gen	1	0.88	0.36
yPower.gen.wind	1	0.41	0.53
yPower.gen.solar	1	1.19	0.29
yPower.gen.chp	1	0.33	0.58
yPower.gen.hydro	1	0.11	0.74
yPower.gen.ren.excl.hydro	1	0.34	0.56
yPower.gen.ren.incl.hydro	1	0.03	0.87
yPower.gen.nonren	1	1.44	0.24
yPower.gen.thermal	1	1.40	0.25
yPower.gen.nuclear	1	1.22	0.28
yPower.gen.gas	1	5.33	0.03
yPower.interconnect	1	1.80	0.22
yPower.peak	1	1.43	0.25
yPower.reserve	1	0.00	0.97
yService.pop	1	1.19	0.29
yService.res	1	1.21	0.29
yService.pop.urban	1	0.03	0.87
yService.res.urban	1	0.00	0.95
yService.popgrowth	1	0.44	0.52

Table 8-6 Second stage analyses (2)

yService.connection.ehv	1	0.07	0.79
yService.connection.hv	1	2.11	0.17
yService.market.volume	1	0.40	0.56
yService.market.value	1	0.55	0.51
yService.market.incumbent	1	0.06	0.81
yService.price.ind	1	0.00	0.98
yService.price.res	1	0.00	0.97
yService.tax	1	0.53	0.47
yEnv.area	1	0.35	0.56
yEnv.area2	1	0.05	0.82
yEnv.area.lake	1	1.71	0.21
yEnv.area.forest	1	1.34	0.26
yEnv.area.agri	1	0.10	0.75
yEnv.area.roads	1	23.21	0.00
yEnv.area.alps	1	0.52	0.55
yEnv.area.resid	1	0.06	0.81
yEnv.temp.summer	1	0.23	0.63
yEnv.temp.winter	1	1.04	0.32
yEnv.temp.max30	1	0.47	0.50
yEnv.temp.min30	1	1.17	0.29
yEnv.rain	1	0.31	0.59
yTowers.steel	1	1.32	0.26
yTowers.cable	1	0.70	0.41
yTowers.wood	1	0.91	0.35
yTowers.other	1	4.94	0.04
yDensity	1	0.00	0.97
yAgem	1	0.87	0.36

8.72 We have therefore evaluated the two resulting extensions of Model 3.

8.73 Extending with yPower.gen.gas is potentially interesting since it lowers the deviation measure to D = 0.632. The resulting model, however, exhibits a high correlation with our preferred model and a close investigation shows that only three TSOs are affected by the extension. Since one of them is a rather inefficient outlier, and since this is improving considerable by the inclusion of gas, this explains the decline in D. We therefore do not find it relevant to extend the model with gas generation

8.74 The introduction of yEnv.area.roads, an alternative topology proxy based on total road length, is potentially interesting but infeasible since we only have this information for 12 out the 22 TSOs.

Age effects

8.75 To test the hypothesis that the age structure of the assets may directly explain costs or performance indicators, the share of grid capital per time

period (pre-65, 1965-1969, 1970-1979, etc) were calculated for all grids, illustrated in Figure 8-1 below. The indicator for pre-1965 assets was not significant either in the explanation of cost (OLS) or in a second-stage calculation (Tobit). A quick inspection of the figure reveals the reason, the benchmarking peers are found uniformly distributed in terms of asset age.

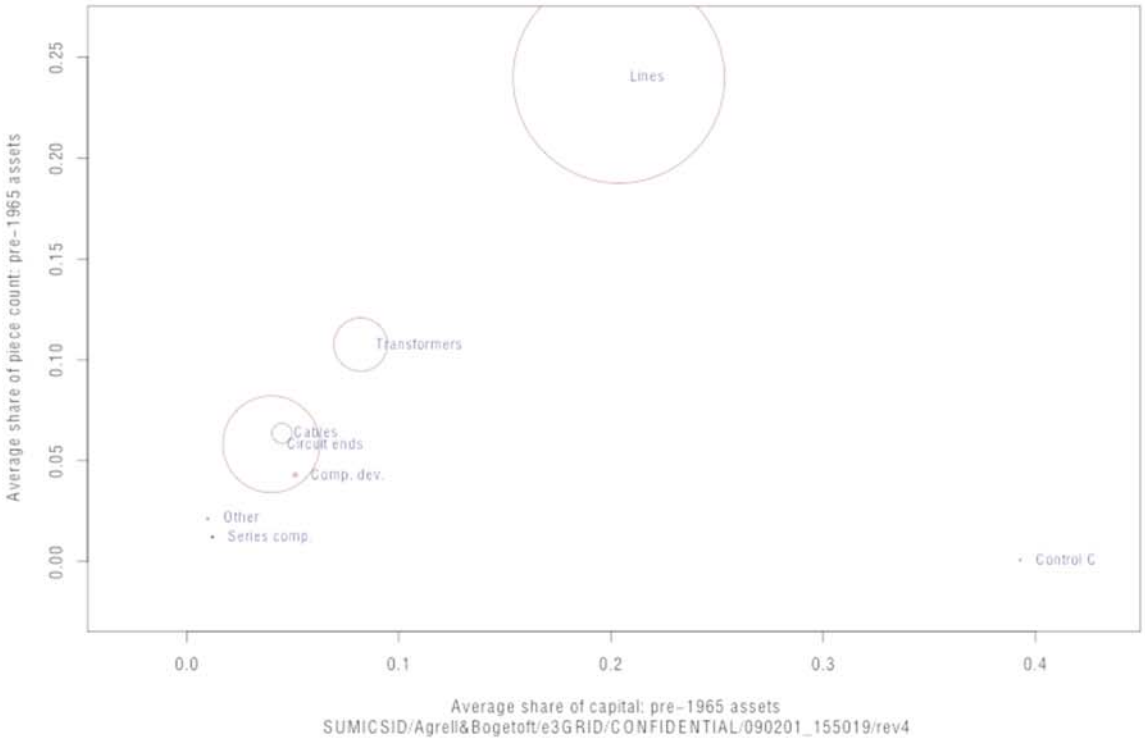


Figure 8-1 Age per asset type per unit and capital share, area represents share of total capital for the 22 grids.

8.6 Dynamic results

8.76 Consistent with the focus for the static results, we present dynamic results for the preferred model 3 with the scope CMPA under Totex.

8.77 In addition to the panel results for nine TSOs with full data for all years 2003-2006, for which preliminary results were presented in the interim report Dynamic Results (R2), we also present a shorter panel using 16 TSOs 2005/2006.

8.78 We have calculated not only the Malmquist efficiency scores MA for the period but also the decomposition of these into Efficiency Change (EC) and

Technical Change (TC). While MA captures the net change of productivity, EC captures catch-up effects and TC captures frontier shifts.

8.79 The average results across the TSOs in each period and across periods are shown in Table 8-7 below. We note the stability of the relevant results using both the long and short panel, indicating that the annual Totex efficiency improvement rate for best-practice operators averages around 2.2% - 2.5% during the period 2003-2006. Detailed analysis of the cost shares per activity reveals the nature of these productivity gains, where some functions and costs have increased in real terms during the period and others have been decreased due to rationalization and economies of scale. It is interesting to note that the average productivity growth (M) is positive and relatively strong for the longer panel (3.5%), thanks to a 1.3% catch-up rate for the inefficient operators, while this is not the case for the shorter panel. Although conclusions from dynamic analyses should not be drawn from shorter samples than 3-4 years, one may speculate whether there could be learning and adoption effects for operators unbundled and regulated using incentive regulation earlier.

Table 8-7 Dynamic efficiency results.

Sample	MA0304	MA0405	MA0506	Average
9	1.035	1.059	1.012	1.035
16			1.009	1.009

Sample	EC0304	EC0405	EC0506	Average
9	1.025	1.023	0.991	1.013
16			0.985	0.985

Sample	TC0304	TC0405	TC0506	Average
9	1.008	1.035	1.022	1.022
16			1.025	1.025

8.7 Summing up

8.80 To sum up, the benchmarking models have shown that the normalized grid measure Totex (NormGridTotex) is a very useful cost driver aggregate, that Density is also an important cost driver and that the connected renewable energy resources is a likely although more marginal cost driver. The used of non-parametric outlier analysis proves to be effective to detect a number of outliers using a diverging technology, which also renders the use of tower-indicators unnecessary (non-significant).

8.81 We have seen also that there are likely economies of scale in the grid size. In a DEA framework, this cannot be modeled by the assumed convexity of DEA model by assumption, but the NDRS model at least allows for dis-economies of being small and no diseconomies from being large.

8.82 We have also seen that SFA modeling is difficult by the large variation in performance and the small number of observations, and that it is probably most sensible to analyze performance in sub-samples.

8.83 In summary, we conclude that the analysis provides cautious and reliable efficiency estimates with respect to benchmarked Totex and AdjTotex (and hereby benchmarked Opex efficiency) for the scope Construction, Maintenance, Planning and Administration (CMPA).

8.84 The dynamic productivity analyses have identified a current, sector relevant and reasonable estimate of real efficiency growth (frontier shift) equal to approximately 2% per year. The estimate is consistent with that obtained using a shorter sample and earlier results.

9. Sensitivity analysis

9.1 Scope

9.01 The underlying model employs a considerable multi-dimensional data material to derive results at a relatively aggregate level. The techniques to arrive at this aggregation are standardization and normalization of individual data. Naturally, the process depends on the choice of a set of parameters, defined above, and their values. In this section we document part of the sensitivity analysis made for the results in the e3GRID project. Graphs and tables illustrating the impact on specific choices on individual operators cannot be published in this section due to confidentiality agreements, since relative data coupled with qualitative information about the costs and asset structure would enable deductive identification of firms.

9.02 The parameters chosen for sensitivity analysis in this section are the real interest rate, the scaling parameters R and Rc, the asset weights, the salary compensation index and the opening balances' influence.

9.2 Sensitivity analysis on interest rate

9.03 The sensitivity of the scores with respect to the interest rate is low, as seen graphically from the average values in Figure 9-1 below where the interest rate has been changed from 0.24 % to 9.36% (-95% to +100% of actual value). In particular, decreasing the interest rate by 50% would change the mean score by 0.003 %-units. The result is similar to earlier findings and is explained by the shared dominance of Capex in the cost function, creating similar impact across operators, and the fact that operators with particularly favorable Capex performance are already efficient in the NDRS model.

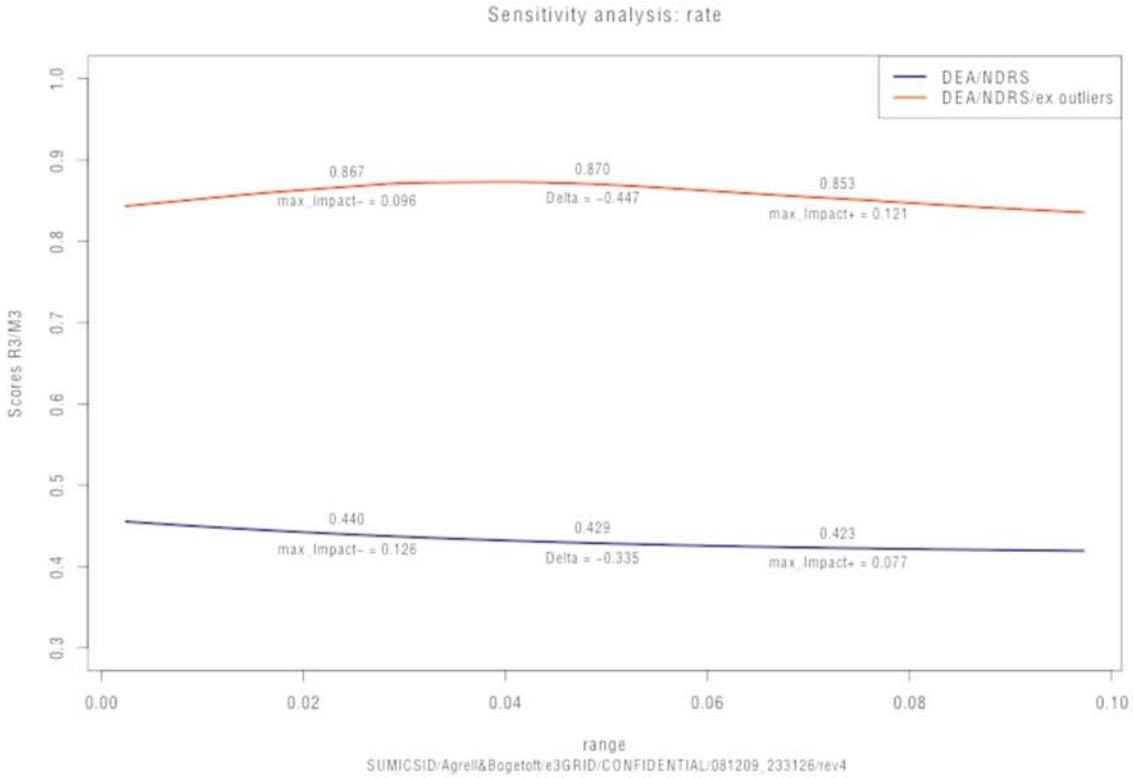


Figure 9-1 DEA NDRS and NDRS/excluding outliers as a function of real interest rate, *r*.

9.04 The findings for the NDRS model excluding outliers in Figure 9-1 confirm the conclusions above, but also underlines that the current setting indeed provides the overall most favourable view on the operators performance (a maximum around the plausible levels 3.5% - 4.5%. max_impact+ denotes maximum impact on the score on any operator for a 50% change in the value, here an increase to 7.5% real interest would affect the score by 12% relative for some operator, but since the mean score only changes by 1.7%-units, the impact must be low).

9.3 Sensitivity analysis on scaling constant R

9.05 The scaling constant R is a technical parameter that is used to calibrate the proportion of Opex to Capex in the calculation of the normalized grid metric. The NormGrid metric is monotonously increasing in R, the Unit Cost metric is monotonously decreasing. However, since the normalized grid metric here serves only as a normalization basis, the impact on DEA scores (Figure 9-2) is negligible.

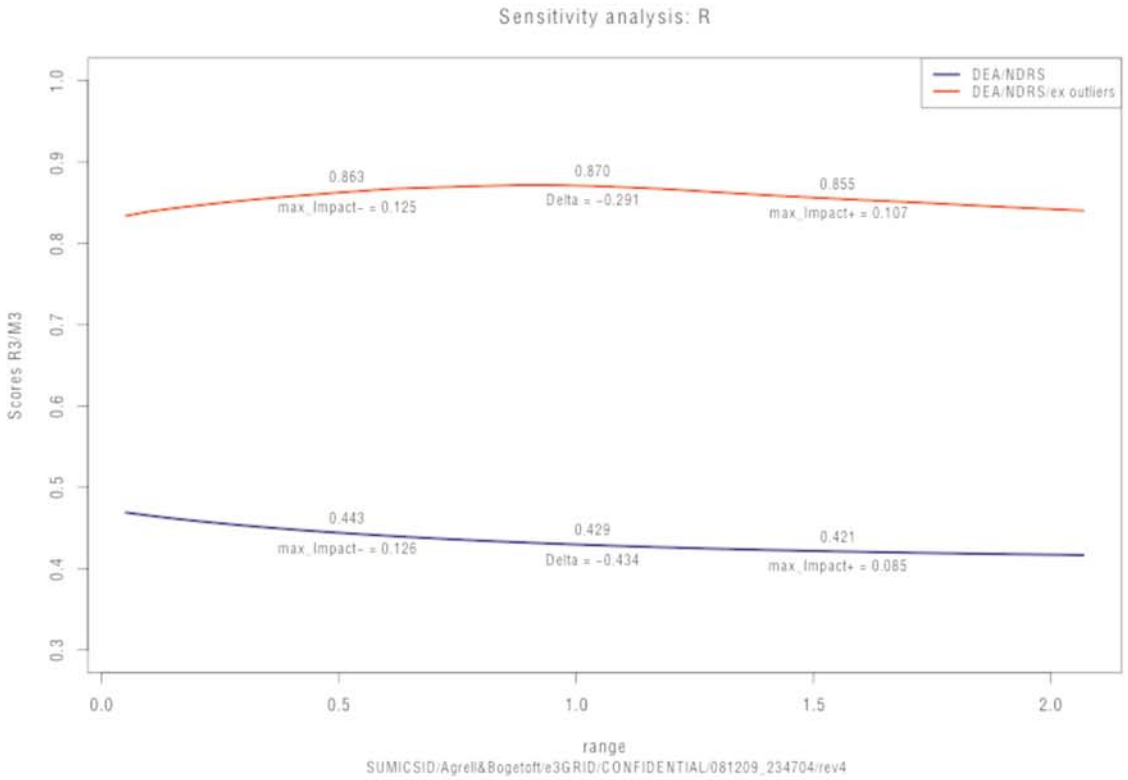


Figure 9-2 Mean DEA NDRS scores as a function of scaling constant *R*.

9.4 Sensitivity analysis on scaling constant Rc

9.06 Analogously to the analysis in subsection 9.3, the impact of another calibration parameter (Rc) on any relative scores is virtually nil as seen in Figure 9-3 below. The rather technical result is a consequence of the fact that the volume of technically depreciated but operational assets (i.e. Opex but no Capex in the model) per operator is relatively limited and only marginally impacts the score.

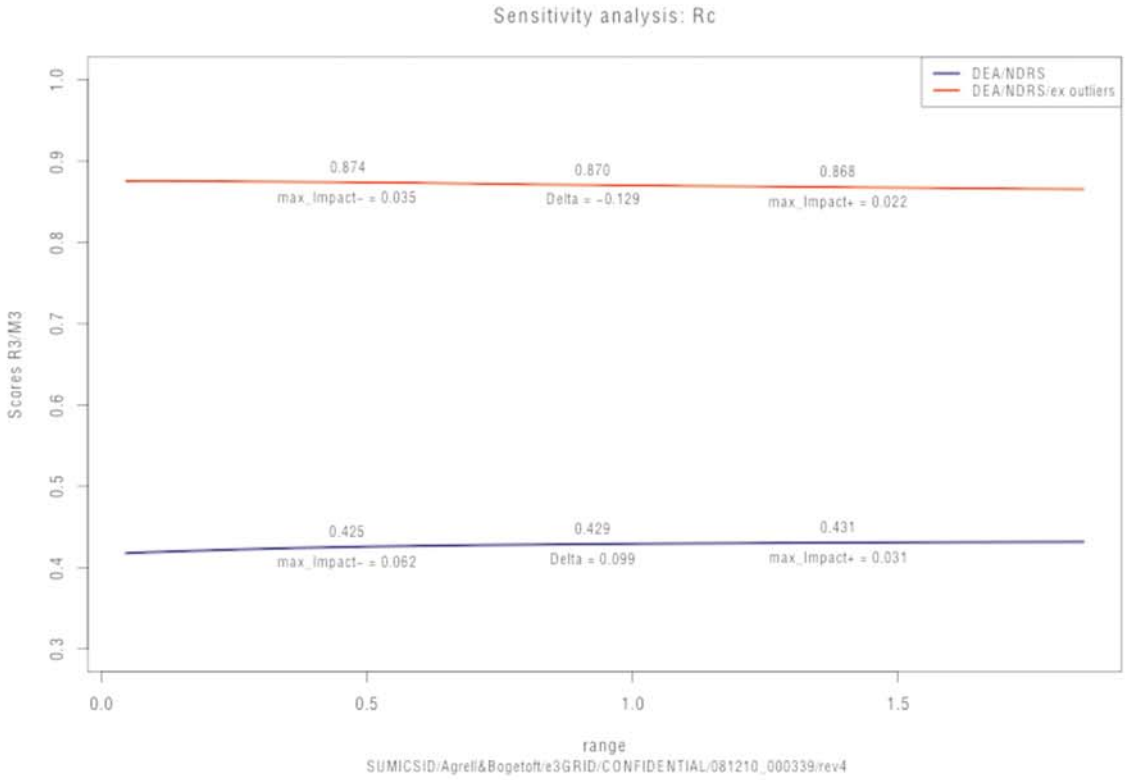


Figure 9-3 Mena DEA NDRS score as a function of scaling constant Rc.

9.5 Sensitivity analysis on asset weights

9.07 The asset weight system contains 1222 unique items in eight asset groups. It would not be informative and relevant to reproduce (or even perform) analyses on each of these items individually. Below, we have chosen to investigate the impact of an individual change of the level of a group, *ceteris paribus*. Knowing that the impact of a group change constitutes an upper bound to the sensitivity with respect to any item or subset of the group, this approach is a generally applied technique in sensitivity analysis.

9.08 In each graph, Delta indicates the slope of the mean score function with respect to the weight. I.e. Delta= -0.0068 in Figure 9-4 indicates that an increase of the weight by e.g. 10% would result in lowering the mean score by 0.1 × 0.0068 = 0.00068 (absolute). As seen in all graphs, the sensitivity to the scores is generally very low for mean scores, the highest being transformers with 0.0148, which suggests 2.5%-units change in mean efficiency for a doubling (200%) of the weights. Generally, the span –/+ 20% results in changes to the relevant results that do not change the second decimal of the mean efficiency score.

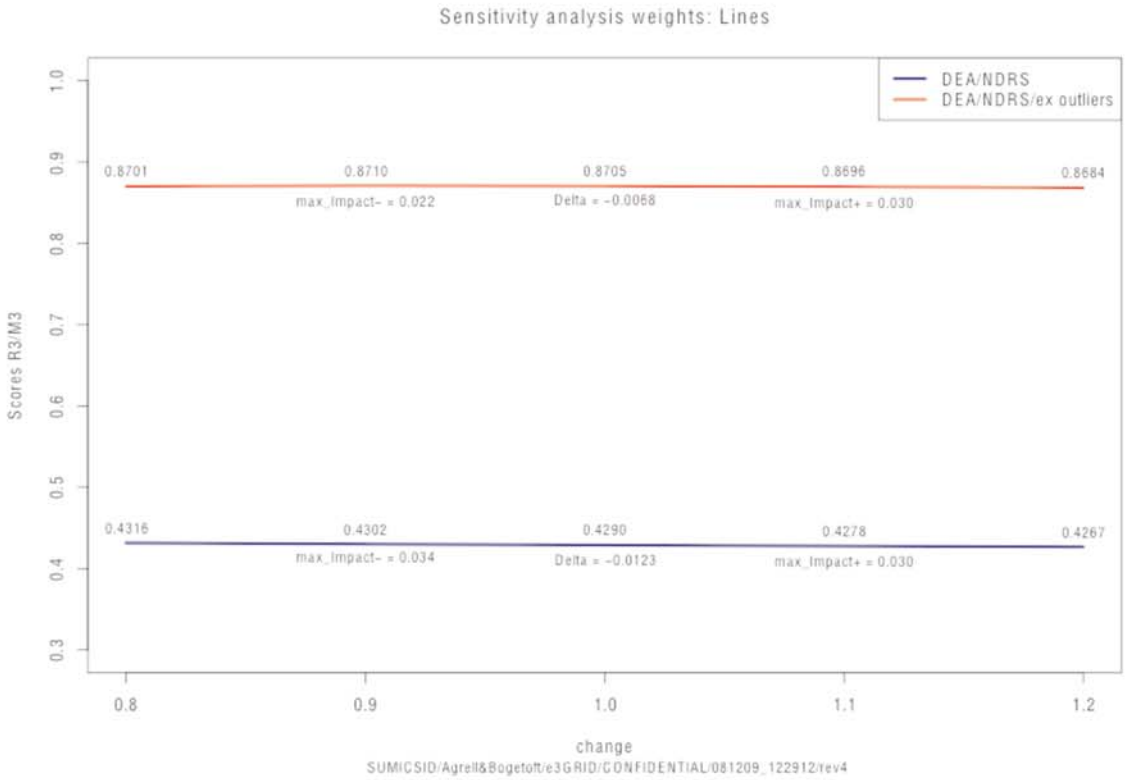


Figure 9-4 Mean DEA scores as a function of changes in the weight on overhead Lines (cat 010).

9.09 However, an additional indicator of sensitivity may be the maximum change of any individual score compared to the base case when changing the parameter value. This would pick up the problem of individual operators being hurt by erroneous weights for which no other units have assets, thus not showing significant results for the impact on the mean. In Figure 9-4 throughout Figure 9-11, max_impact+ indicates the maximum change (ratio of DEA scores compared to base case) for a decrease of 20% of the weights in the group. For cables, this would amount to 2% (on the score). Similarly, max_impact+ reports on the maximum change in individual efficiency for an increase of 20% in the weights of the group.

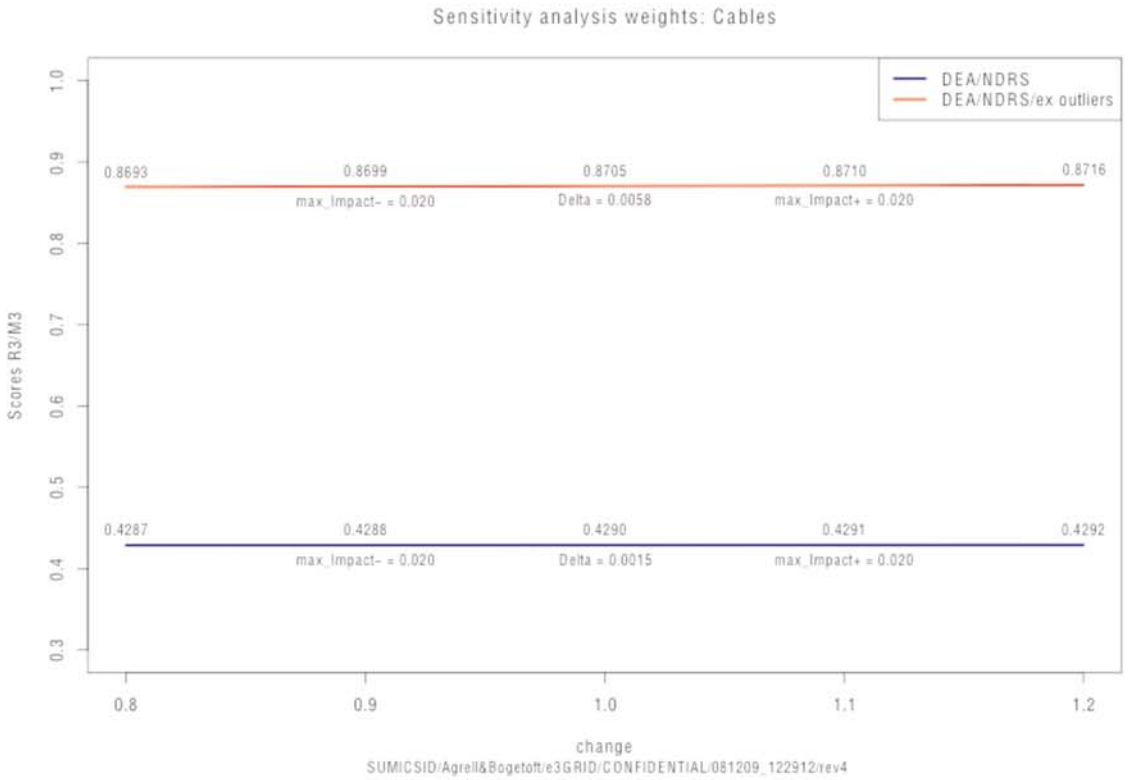


Figure 9-5 Mean DEA scores as a function of changes in the weight on sea and land Cables (cat 020).

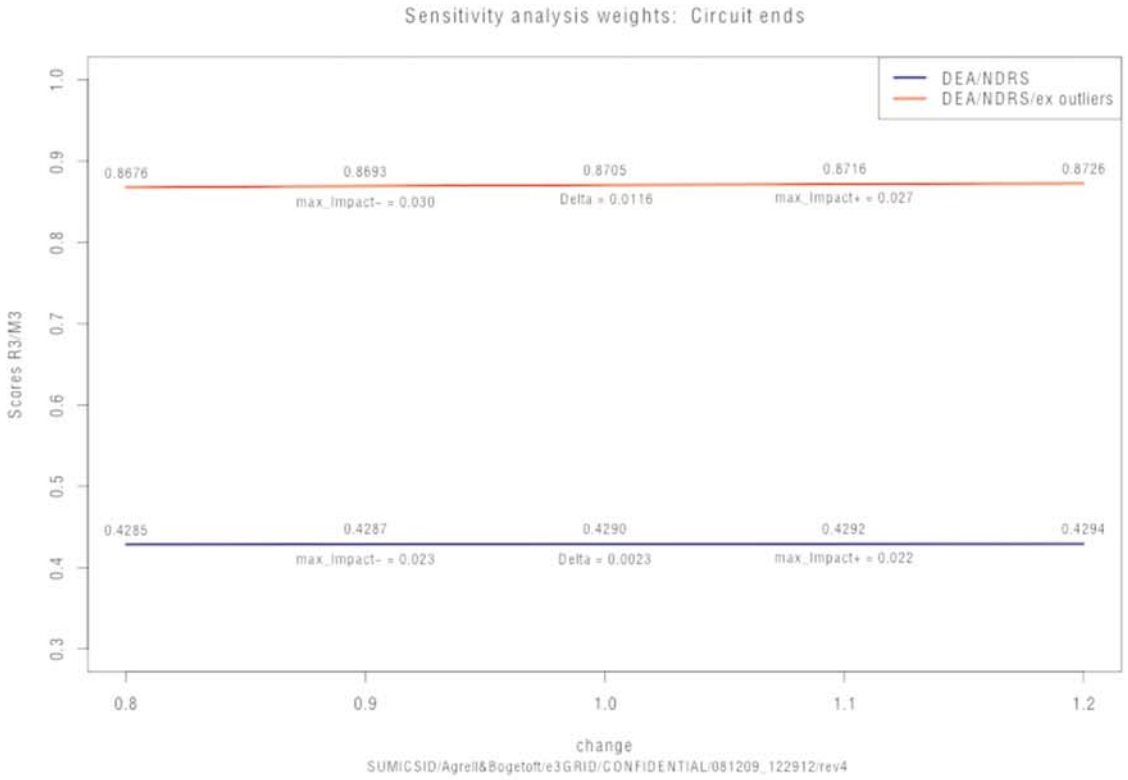


Figure 9-6 Mean DEA scores as a function of changes in the weight on Circuit ends (cat 030).

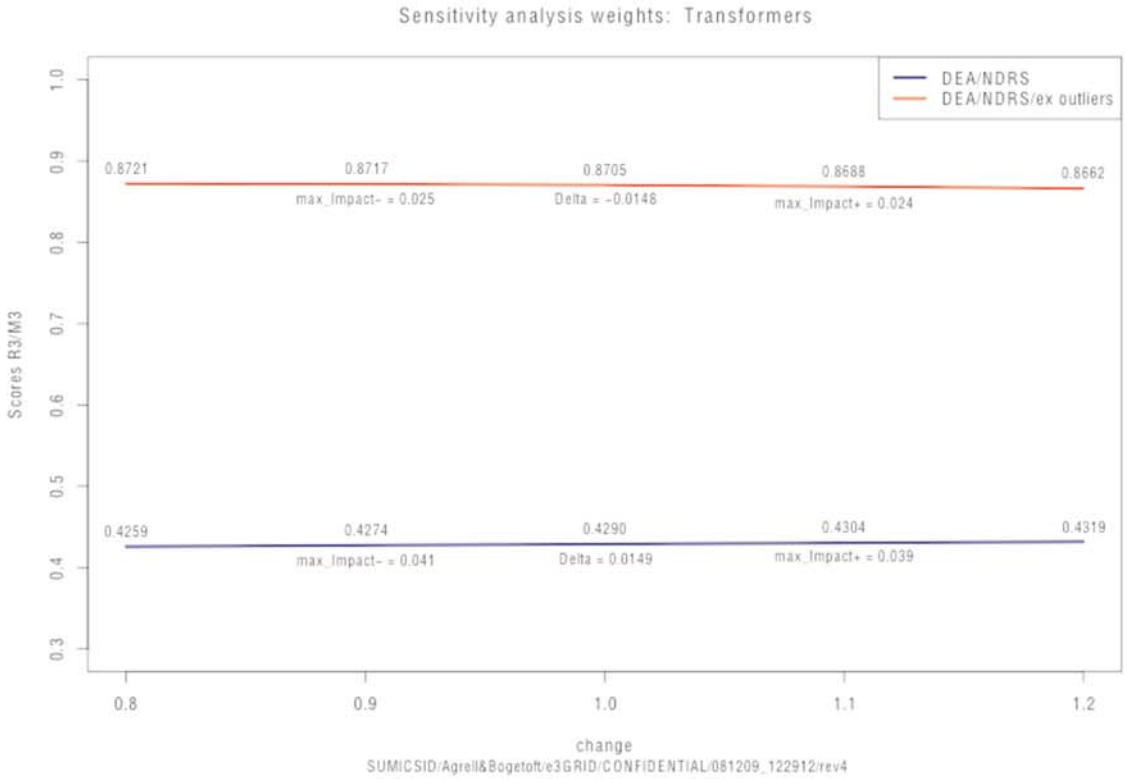


Figure 9-7 Mean DEA scores as a function of changes in the weight on transformers (cat 040).

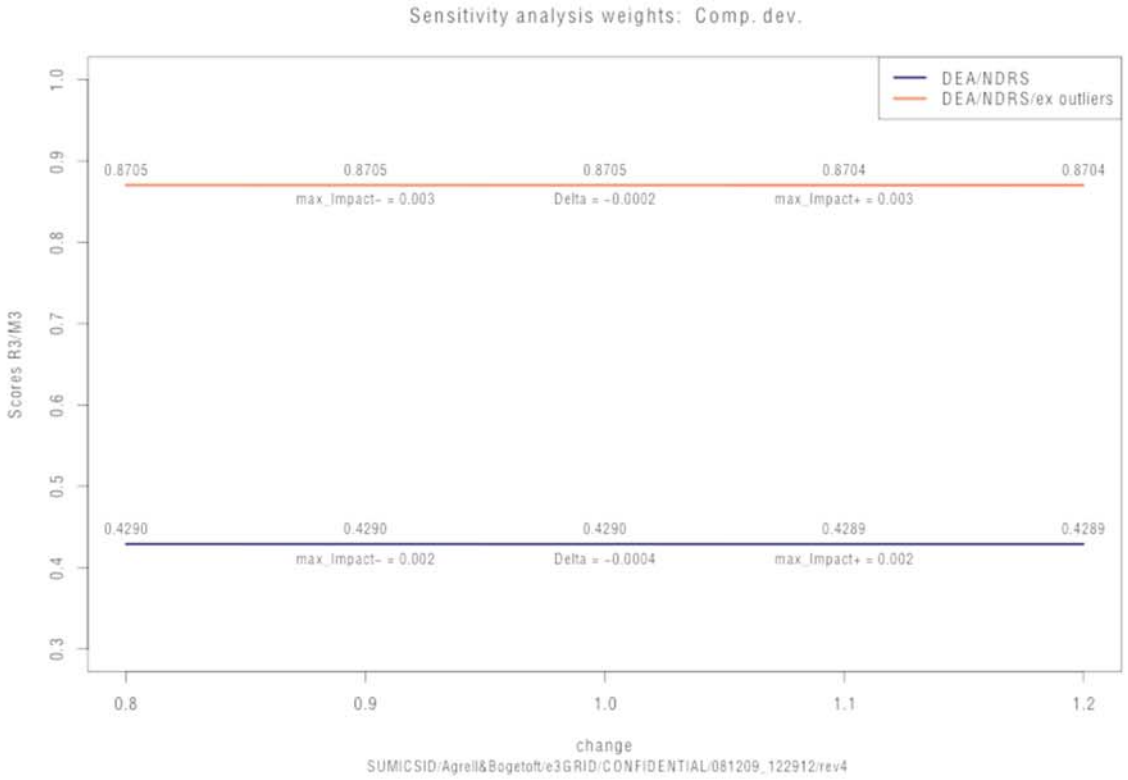


Figure 9-8 Mean DEA scores as a function of changes in the weight on Compensating devices (cat 051)

9.10 We may conclude from the weight analysis that the weights, in addition to the regression results showing good explanatory power for both Totex and Capex, also form a stable and robust normalization base for the grid systems. Although individual weights may be questioned from time to time under different operating contexts, what matters for the objectives of the benchmarking is whether they, as a system, achieve a comparable indicator of the grid asset base.

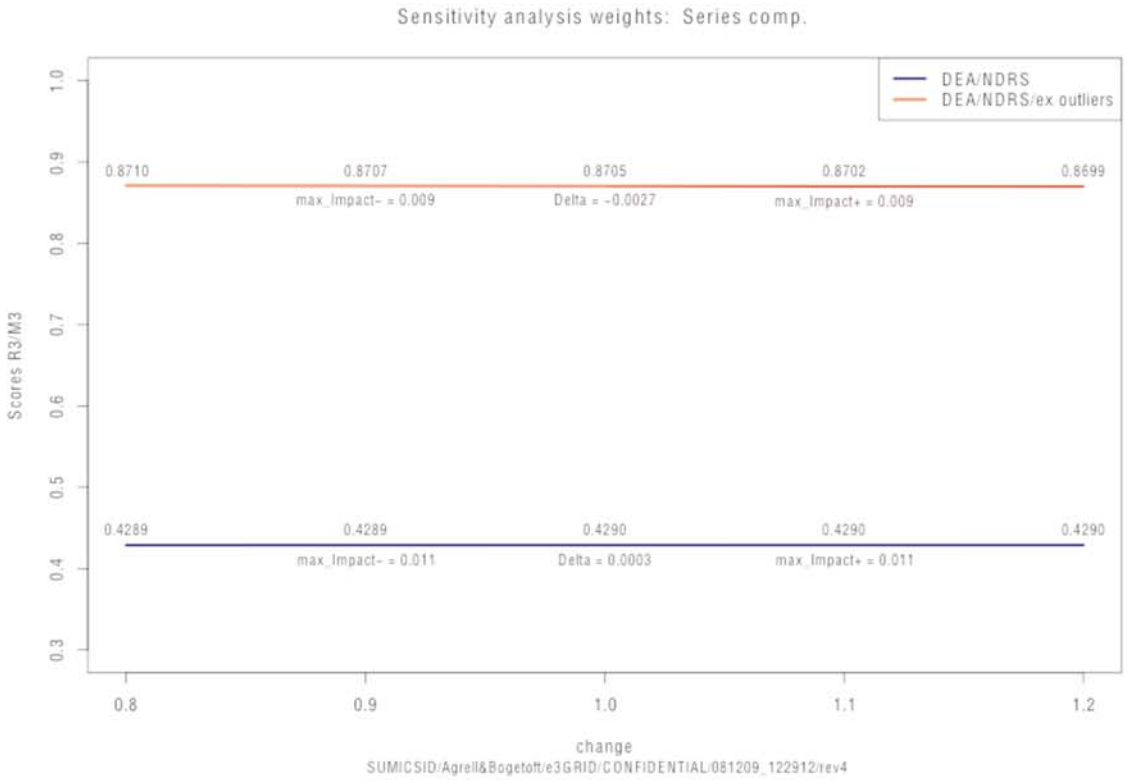


Figure 9-9 Mean DEA scores as a function of changes in the weight on Series compensation installations (061).

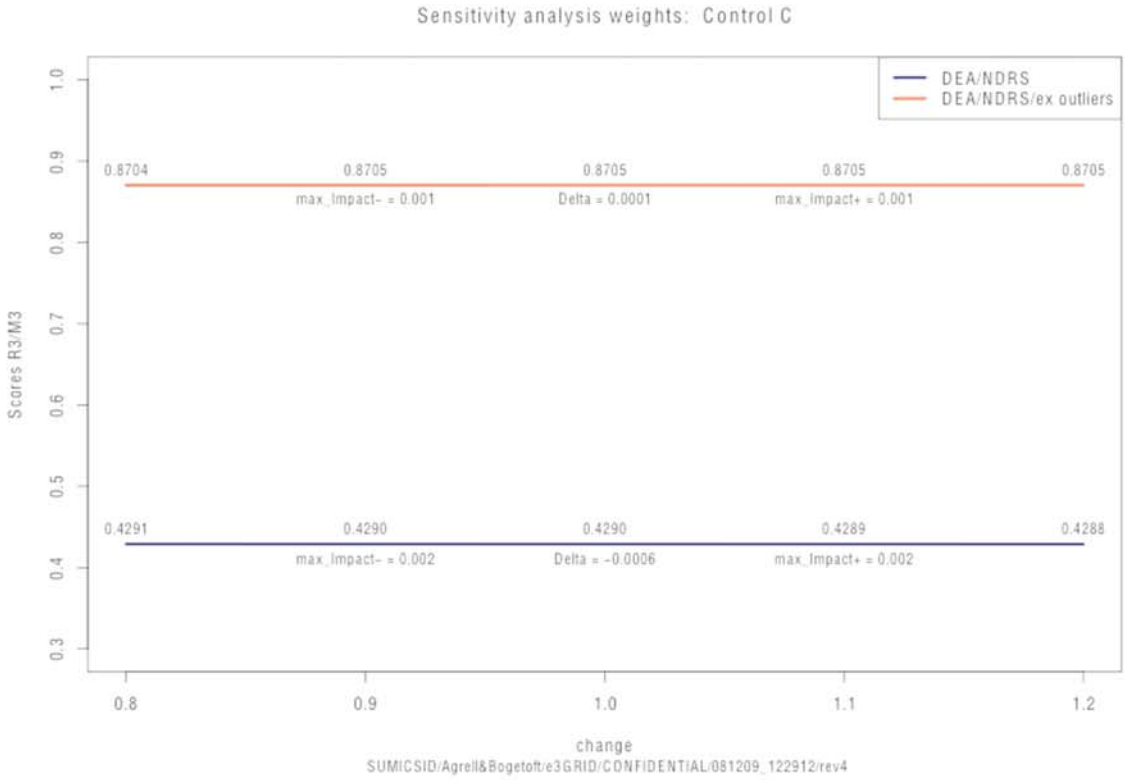


Figure 9-10 Mean DEA scores as a function of changes in the weight on Control Centers (cat 071).

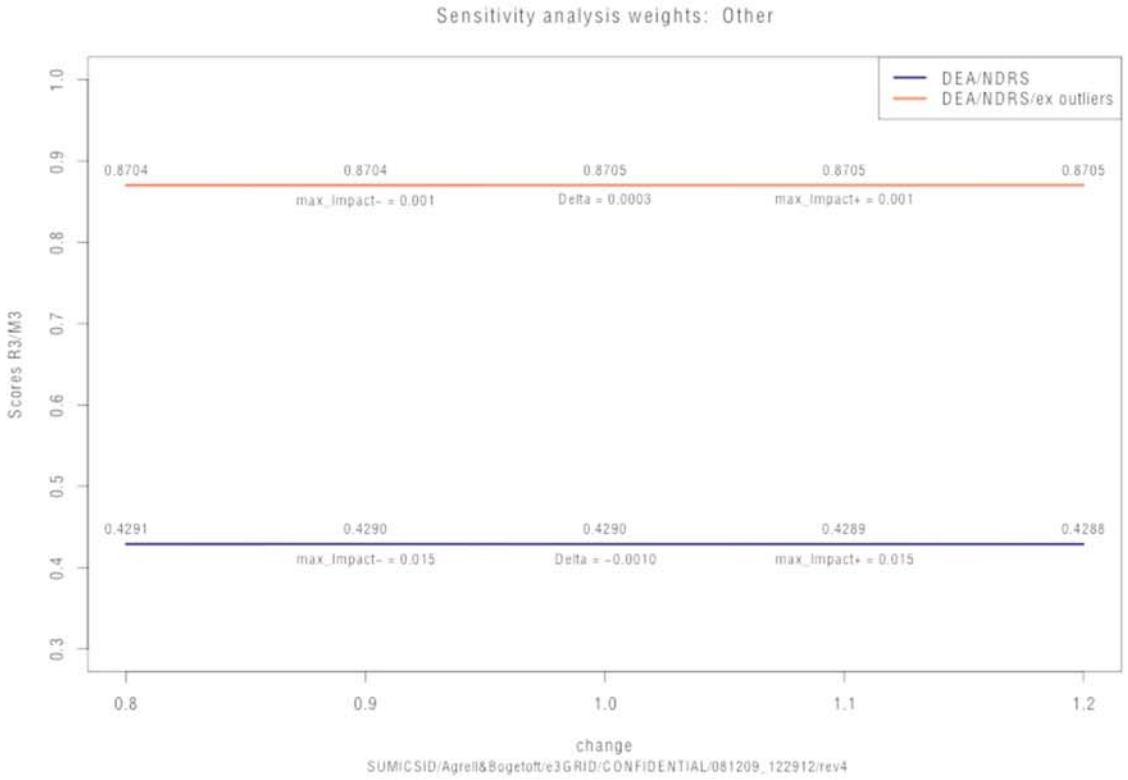


Figure 9-11 Mean DEA scores as a function of changes in the weight on Other assets (cat 091).

9.6 Sensitivity analysis on compensation indexes

9.11 The salary index used in the main calculations, the European TSO salary index calculated already in the interim e³GRID report Static Results (R1) and revised in the second interim report Dynamic Results (R2) has been compared to two alternatives (no correction and regional salary correction). Simple inspection shows that the used index yields the average efficiencies that are higher than the case without correction, and that the correction with the regional index follows the European one very closely in terms of results. For the DEA model including outliers, the inter-index correlation is 99% with less than 1%-unit difference in mean score between any two indexes. For the relevant DEA model without outliers, the inter-index correlation between the two corrections is still 99%, but the correlation decreases to 92% compared to without correction. Without going into details for TSOs, the impact of the salary compensation index depends on staff intensity and whether the average compensation cost is

higher or lower than the European average. For some countries in regions with lower than average compensations, their benchmarked cost will be "padded" with a supplement to assure structural comparability for the sample and vice versa for countries in high-cost regions. Mean value analysis shows that the salary index lowers the variance in staff compensation costs (by construction), individual analysis may by useful for cases where particular conditions apply for the staffing policy and compensation.

9.7 Sensitivity to opening balances

9.12 Half of the TSOs in the study have supplied only part of the historical investment stream due to the fact that they are unbundled late, assets are reevaluated or the historical investment streams contain (fully depreciated) assets that are currently owned by other firms (distribution or generation). It was a concern raised by the TSOs in the study that the conditions for establishing the opening balance may be influenced by other than managerial factors, such as legal, political, regulatory and macro-economic factors prevailing at the time of the unbundling. Since the Totex score is strongly influenced by Capex costs in a capital-intensive industry, the sources of this temporal Capex "efficiency" may then be non-replicable and, in extension, pose comparison problems. To address this issue, an analysis has been made using re-estimated opening balances for those operators that have less than a full investment stream.

9.13 The logic behind the correction is based on the assumption that the investment behaviour after the unbundling is the best indication of the managerial behaviour prior to the unbundling. I.e., we estimate a mean Capex efficiency for the observed horizon, say W, as the ratio of inflation adjusted investments to normalized grid intensity for each investment year. Since the mean is used, lack of timing should no be crucial in this estimation. The corrected opening balance is then obtained as the sum of normalized grid assets up to and including the unbundling year, multiplied with the empirical Capex efficiency.

9.14 The situation prior to correction shows a certain spread with respect to Capex. A further analysis, also based on unit cost shows that with the exception of two operators, most obtain lower unit cost results due to Capex and that the span of observations in Opex is considerably lower.

9.15 The adjusted data for the capital correction produces a new outlier, but generally contributes to a closer fit between the Opex and Capex measures. However, the original scores are relatively robust to the

opening balance corrections, the mean value for DEA NDRS (model 3) increases by 1.3% units and the scores for DEA NDRS excluding outliers by 1.5%-units. The analysis is developed as part of the sensitivity analysis and is not seen as an alternative to other models.

10. Conclusion

10.1 Reported work

10.01 This report documents a considerable and fruitful joint effort of transmission system operators, regulators and consultants to define, collect, process and calculate metrics that inform regulatory decisions on the relative performance of European TSOs. A reliable basis can be built only through the strict application of standardized and well-defined concepts in a process characterized by rigorous data validation, transparency and theoretical soundness. The report presents three of the four contributions of the e3GRID project for regulatory use of benchmarking.

10.02 First, the static results obtained using a compact, robust and thoroughly tested model give cautious estimates for the incumbent inefficiency in total cost for construction, planning, maintenance and support for 2006. The results have been subject to a range of tests and can be used as estimates insensitive to the allocation policy between capital and operating expenditure.

10.03 Second, the dynamic results provide useful estimates for productivity and efficiency development in the sector, based on the same total cost model as above. The frontier shift estimates can provide useful information about the expected efficiency development for efficient units in forward-looking regimes such as the determination of a generic X-factor in a revenue-cap review.

10.04 Third, for those regulators that applied a differentiated regulation on capital and operating expenses, the e3GRID also provides a consistent set of operating cost efficiencies using best-practice non-parametric methods. The estimates obtained may be used to develop cost-targets for operating expenses or to monitor productivity growth at operator level.

10.2 Further work

10.05 The fourth contribution is the fruit of the collective effort to establish probably the best regulatory database concerning European electricity transmission operators so far. Regulators may draw on this information to adapt analyses for their individual regulation regimes, including special concerns with respect to cost base, controllability and scope. We believe that this significantly enhanced information base will improve the interaction regulator-TSO and hopefully also contribute to improve effectiveness and predictability in the network regulation.

References

Agrell, P. J. and P. Bogetoft (2000), Ekonomisk Nätbesiktning. Final Report, Swedish Energy Agency, SUMICSID AB. (In Swedish)

Agrell, P. J. and P. Bogetoft (2002a), *Ekonomisk Nätbesiktning 2000*, Report ER 7:2002, Swedish Energy Agency, SUMICSID AB. (In Swedish)

Agrell, P. J. and P. Bogetoft (2002b), *TSO Charter of Accountability*, Final report, SUMICSID AB.

Agrell, P. J. and P. Bogetoft (2003a), *Dynamic Regulation*, Report AG2-V1, Norwegian Energy Directorate NVE, SUMICSID AB.

Agrell, P. J. and P. Bogetoft (2003b), *Norm Models*, Report AG2-V2, Norwegian Energy Directorate NVE, SUMICSID AB.

Agrell, P. J. and P. Bogetoft (2003c), *TSO Benchmarking: ECOM+ Project*, Final report 2003-09-01, SUMICSID AB.

Agrell, P. J. and P. Bogetoft (2003d) *Benchmarking for Regulation*, Report FP4, Norwegian Energy Directorate NVE, SUMICSID AB.

Agrell, P. J. and P. Bogetoft (2004), *Evolutionary Regulation: From CPI-X towards contestability*, ENCORE position paper, Amsterdam.

Agrell, P. J. and P. Bogetoft (2005), *NVE Network Cost Efficiency Model*, Final Report, Norwegian Energy Directorate NVE, SUMICSID AB.

Agrell, P. J. and P. Bogetoft (2006a), *Economic regulation of DER: the norm model approach*, Working Paper WP2.3, EU-DEEP, Fondazione Eni Enrico Mattei (FEEM).

Agrell, P. J. and P. Bogetoft (2006b), *ECOM+ Results 2005*, Final report 2006-06-01, SUMICSID AB.

Agrell, P. J. and P. Bogetoft (2007), *Development of benchmarking models for German electricity and gas distribution*, Final report 2007-01-01 commissioned by Bundesnetzagentur (BNetzA), SUMICSID AB.

Agrell, P. J. and P. Bogetoft (2008), *Electricity and gas DSO Benchmarking*, White paper 2008-04-07 commissioned by Bundesnetzagentur (BNetzA), SUMICSID AB.

Akaike, H. (1969), Fitting Autoregressions for Predictions, *Annals of the Institute of Statistical Mathematics* 21, 243–247.

Banker, R.D., and H. Chang (2006), The super-efficiency procedure for outlier identification, not for ranking efficient units, *European Journal of Operational Research*, 175 (2), pp. 1311-1320.

Battese, G.E. and T.J. Coelli (1992), Frontier Production Functions, Technical Efficiency and Panel Data: With Applications to Paddy Farmers in India, *Journal of Productivity Analysis*, 3, pp. 153-169.

CEER Council of European Energy Regulators (2001), *Quality of Electricity Supply: Initial Benchmarking on Actual Levels, Standards and Regulatory Strategies*, Autorità per l'energia elttrica e il gas.

Coelli, T., and S.Perelman (1999), A comparison of parametric and non-parametric distance functions: With application to European railways, *European Journal of Operational Research,* 117 (2), pp. 326-339

COMILLAS (2002), *Benchmark of Electricity Transmission Tariffs*. Commissioned report for DG TREN, ICADE, Univ. Pontificia Comillas, Madrid.

DTe (2006), *Methodebesluit TennT derde reguleringsperiode*, Bijlage a bij Methodebesluit, DTe, Holland. [In Dutch]

Econ (1999) *Measuring the Efficiency of Statnett*. Report 25/99. ECON Centre for Economic Analysis.

Econ (2002) *ECOM model*, draft report, ECON Centre for Economic Analysis.

Europe Economics (2006) *Research into Productivity Growth in Electricity Transmission and Other Sectors*, Report for DTe.

Frontier Economics (2005) *The cost of capital for Regional Distribution Networks*. Report for Dte [EK].

Frontier Economics (2008) *Updated cost of capital estimate for energy networks*. Report for Dte [EK].

Grifell-Tatje, E. and C.A.K. Lovell (2003) The Managers versus the Consultants, *Scandinavian Journal of Economics*, 105 (1), 119-138.

Hirst, E. (2000) *Expanding U.S. Transmission Capacity*, Edison Electric Institute.

Hirst, E. and B. Kirby (2001) *Transmission Planning for a Restructuring U.S. Electricity Industry*, Edison Electric Institute.

ICF consulting (2002) *Unit cost of constructing new transmission assets at 380 kV within EU*, Norway and Switzerland. Commissioned report to DG TREN.

Judge, G., Griffiths, W., Hill, R. and Lee, T. (1980) *The Theory and Practice of Econometrics*, John Wiley and Sons, New York

Larsson, M. B. O. (2003) *The Network Performance Assessment Model – Regulation with a Reference Network*. Proceedings of the Market Design Conference, 17 June 2003, Stockholm, ELFORSK.

LEK and OXERA (2005), *Assessing Network Rail's Scope for Efficiency Gains over CP4 and Beyond: A Preliminary Study*.

National Grid International (2002), *Final report on the Basslink project*.

Nera (2006) *High Level Efficiency Estimates for the Second Review Period*, Report for the Office of the PPP Arbiter.

Norconsult (1998) *The Bredal-Strømme cost catalogue*. Commissioned report for NVE.

PB Associates (1999) *Snowy Mountains Hydro-Electric Authority: Transmission Asset Based Review*. Commissioned report.

PB Associates (2001) *Powerlink network asset valuation review*. Commissioned report.

Schwarz, G. (1978) Estimating the Dimension of a Model, *Annals of Statistics*, 6, 461-464.

Simar, L. and P. Wilson (2000), A general methodology for bootstrapping in nonparametric frontier models, *Journal of Applied Statistics*, 27, pp. 779-802.

Simar, L. and P. Wilson (2004), *Estimation and Inference in Two-Stage, Semi-Parametric Models of Production Processes*, WP, Department of Economics, University of Texas at Austin, Austin, Texas, USA.

SMHEA (1999) *Regulation of Snowy Mountains Hydro-electric Authority Transmission Assets*. Reply to regulatory hearing.

Syrjänen, M., P.J. Agrell and P. Bogetoft (2006) *Efficiency benchmarking project B: Analogous efficiency measurement model based on Stochastic Frontier Analysis*, Final report commissioned by the Energy Market Authority (EMV) of Finland, Gaia Consulting OY and SUMICSID AB.

Tobin, James (1958), Estimation for relationships with limited dependent variables. *Econometrica* 26 (1), 24–36.

Weatherhill, J. (2000) *Review of First International Workshop on Feasibility of HVDC Transmission Networks for Offshore Wind Farms*, 30-31 March 2000, KTH, Stockholm, Sweden

Wilson, P.W. (1993), Detecting outliers in deterministic nonparametric frontier models with multiple outputs, *Journal of Business and Economic Statistics* 11, pp. 319-323.

Wright, S. , Mason R., Satchell S., Hori K. and Baskaya M. (2006) *Report on the Cost of Capital*. Report for OFGEM, Smithers & Co, London.

Wright S., Mason R. and Miles D. (2003) *A Study into Certain Aspects of the Cost of Capital for Regulated Utilities in the U.K.* Report for UK regulators and OFT, Smithers & Co, London



SUMICSID AB (GROUP)
Tunbyn 502
S-855 90 Sundsvall, SWEDEN
Tel: +46 55 92 15 23
Fax: +32 27 06 53 58
sweden @ sumicsid.com

SUMICSID SPRL (BELGIUM)
Rue de la Piété 11
B-1160 Bruxelles, BELGIUM
Tel: +32 26 75 15 23
Fax: +32 27 06 53 58
belgium @ sumicsid.com

SUMICSID APS (DENMARK)
Fru Ingesvej 19
DK-4180 Sorø, DENMARK
Tel +45 57 83 15 18
Fax: +45 57 83 15 18
denmark @ sumicsid.com

http://www.sumicsid.com