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Internasjonal studie av Statnett sin kostnadseffektivitet

CEER - TCB18

Sumicsid

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Internasjonal studie av Statnett sin kostnadseffektivitet

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Sammendrag: Denne rapporten er en sammenstilling av tre publikasjoner fra studien der Statnett sin kostnadseffektivitet blir målt i forhold til andre europeiske nettselskaper. For sammendrag av innhold, viser vi til sammendraget i hovedrapporten.

Emneord: Statnett, TSO, transmisjonsnett, benchmarking, kostnadseffektivitet, DEA

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Forord

Som ledd i vår oppfølging av Statnett, har NVE deltatt i en studie som har sammenlignet kostnadseffektiviteten mellom 17 europeiske TSOer fra 15 land. TSOer er selskaper som eier og driver transmisjonsnett. CEER, et samarbeidsorgan for europeiske reguleringsmyndigheter innen energi, har bestilt studien. Den er utført av konsulentselskapet Sumicsid, TSOer og reguleringsmyndigheter har bidratt med data og innspill underveis i studien, og NVE har deltatt i styringsgruppen for prosjektet.

Konsulentene har levert en hovedrapport som er et offentlig dokument. Hovedrapporten inneholder beskrivelse av studien og anonymiserte resultater. Til hovedrapporten følger også et vedlegg med ytterligere detaljer fra studien. I tillegg har konsulentene laget en landspesifikk rapport per land. Denne er kun delt med regulatormyndighet og TSO i det aktuelle landet. Her vises resultatene for landets TSO. Denne rapporten er en sammenstilling av alle tre publikasjonene fra studien.

Innholdet i denne rapporten står for konsulentens regning.

Alle resultater i studien er deskriptive, og rapportene inneholder ingen diskusjon om hvilke implikasjoner resultatene bør ha for reguleringen i det enkelte land. Det vil alltid være mer usikkerhet i internasjonale studier enn nasjonale. Dette er knyttet til om forutsetningene i modellen fanger opp alle relevante forskjeller mellom land på en rimelig måte. Usikkerheten i denne studien øker ytterligere fordi vi har begrenset tilgang til datagrunnlag og resultater for de andre selskapene i studien. Vi vil derfor ikke anvende disse resultatene «mekanisk» i den økonomiske reguleringen av Statnett.

NVE følger opp Statnett gjennom ulike rapporteringer og studier. Resultatene fra denne studien er et viktig bidrag til kunnskapsgrunnlaget vi bruker for å regulere Statnett.

Oslo, september 2019

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direktør,
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seksjonssjef

PROJECT CEER-TCB18

Pan-European cost-efficiency benchmark for electricity transmission system operators

MAIN REPORT

2019-07-17 V1.2

Disclaimer

This is the final report of a CEER project on cost efficiency benchmarking that involves data collection, validation and calculation of various efficiency indicators. Respecting the confidentiality of the submitted data and the prerogatives of each national regulatory authority to use or not the information produced in review of network tariffs or other monitoring, the report does not contain details for individual operators, nor comments or recommendations concerning the application of the results in regulation. In addition to this open report, each regulator and participating operator has also received a more detailed confidential analysis.

Pan-European Cost Efficiency Benchmark for Electricity Transmission System Operators
Final report. Open. Project no: 370 / CEER-TCB18
Release date: 2019-07-17

Executive Summary

The Transmission Cost Benchmarking project 2018 (TCB18) is an initiative by the Council of European Energy Regulators (CEER) to initiate a stable and regular process for performance assessment of energy transmission system operators. The project covers both electricity and gas transmission and involves in total 46 operators from 16 countries in Europe. The project is the most ambitious regulatory benchmarking project documented so far, mobilizing national regulatory authorities (NRA), transmission system operators (TSO) and consultants in a joint effort to develop robust and comprehensive data and models. The project lasted from December 2017 to June 2019, involving five workshops and three successive stages of project setup, data collection and validation, followed by calculation and reporting.

Comparability
The primary challenge of any benchmarking is assuring comparability among observations emanating from operators with differences in organization, task scope and asset base. This challenge is addressed by (i) limiting the scope to comparable activities in transport and capacity provision, (ii) controlling to systematic differences in labor costs, (iii) standardizing the asset life-times and capital costs to equal conditions, (iv) excluding country-specific cost factors (land, taxes), (v) controlling for joint assets and cost-sharing, (vi) adjusting capital costs for inflation effects.

Reliability
The benchmarking is performed on NRA collected data, subject to a multi-stage data quality assurance process and using state-of-the art benchmarking methods such as Data Envelopment Analysis (DEA). The reliability and replicability of DEA results are immediate, since the method does not depend on any *ad hoc* parameters, but relies on the input data and linear programming. The environmental, economic and technical parameters and indices used have been collected from public sources based on clear techno-economic arguments. The sensitivity analysis shows that the results are robust to these latter assumptions. Globally the reliability of the method and the results is very good.

Verifiability
The quality of the data material in the project is a key determinant of the precision of the project results. The project addresses this criterion (i) by issuing and validating data collection guides and templates to avoid the use of incomparable data sources at an early stage, (ii) by defining a clear NRA validating procedure, (iii) by organizing a cross-validation process for both technical and economic data through the consultant, (iv) by fully disclosing all processed data to each respective operator for control and confirmation to avoid misinterpretations and error, (v) by organizing interactive workshops to enable questions, and (vi) by providing online support on the project platform for submitting operators and NRAs.

Confidentiality
The data involved in the study go deeply into the operational efficiency of the participating operators. As this data are of crucial economic importance to the enterprises, the integrity and confidentiality of the data are taken seriously in the project both from structural, procedural and organizational viewpoints. Although transparency has advantages in data validation and interpretation of the results, the current project setup respects the concerns of operators not wishing to reveal the individual information or scores.

Approach
The methodological approach in the study has been to proceed independently with the estimation of a proxy for the diversified asset base of the operators, called the normalized grid or NormGrid. This system, constructed by international transmission system engineers based on transmission cost functions, provides a totex-relevant proxy for comparing operators in terms of size. The resulting metric was then tested by another team on the actual data, confirming the strong explicative value of the NormGrid. Quality provision was subject to a specific survey to assess potential indicators, but the results from this survey could not be directly applied to the model.

Environmental factors
The engineering team continued to develop testable hypothesis for the cost impact of various relevant environmental factors. After collection of such data, partially using a very detailed GIS-supported data set for each TSO, an analysis was made to enhance the NormGrid parameter with an environmental correction multiplier to adjust for heterogenous operating conditions. Other parameters were tested and included if not covered by correlation to the already incorporated factors or the grid in itself (NormGrid).

Activity model
Based on a multi-dimension performance model, additional parameters were selected based on their statistical and techno-economic significance to form a final model with one input, totex and three output parameters; NormGrid corrected for landuse (area type), total transformer power, and the line length corrected for angular and steel towers. The final model caters for all three performance categories; transportation work, capacity provision and customer service.

Benchmarking results
The model shows that the electricity transmission system operators had a mean cost efficiency of 89.8% for 2017, with four frontier outlier operators and four best-practice peers. The results confirm earlier findings both in terms of level and distribution of scores, meaning that there likely is an efficiency potential corresponding to about 10% of total comparable expenditure. The result corrects for salary differences, heterogenous opening balances, unequal length of investment streams and overhead cost allocation rules.

Robustness
The results show a stable rank order with respect to the parameter interest rate and very low sensitivity in general to changes in the NormGrid system weights. The outlier identification procedure limits also the impact of operators with very specific cost structures that might be non-replicable for non-peers.

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1. Project objectives and organization

In this Chapter we state the project objectives, the organization and the report outline.

1.1 Main objectives

1.01 The main objective with the CEER TSO Cost efficiency Benchmark 2018 (project TCB18) is to produce a robust and methodologically sound platform for deriving cost efficiency estimates for transmission system operators, under process and data quality requirements allowing use of the results to inform regulatory oversight of the operators. In the project, best practice TSOs (forming the so-called frontier) are identified and related to other TSOs in a pan-European and regulatory context. Ultimately this is the purpose of TCB18.

1.02 TCB18 succeeds the E3GRID project in 2012/2013 and the E2GAS study of 2015/2016, combining in a single project a benchmark of gas TSOs and electricity TSOs. This report deals with the electricity study. The gas part is described in a separate report.

1.2 Project management

1.03 TCB18 is owned and initiated for regulatory purposes by CEER, the Counsil of European Energy Regulators. CEER has hired Sumicsid for advise and to perform parts of the benchmark study, notably analysis, modelling, and reporting.

1.04 Daily management of TCB18 is done by a project steering group (PSG) that consisted of representatives from ACM (Dutch NRA), BNetzA (German NRA), CNMC (Spanish NRA), NVE (Norwegian NRA), PUC (Latvian NRA), and Sumicsid (consultant). The PSG held regular meetings about every two weeks plus ad hoc meetings to discuss and decide about issues.

1.3 Project deliverables

1.05 The project produced two deliverables to document the results and the process:

1.06 **Final reports**:
This document for electricity constitutes the final report documenting the process, model, methods, data requests, parameters, calculations and average results, including sensitivity analysis and robustness analysis. The report is intended for open publication and does not contain any data or results that could be linked to individual participants.

1.07 **TSO-specific reports:**
Clear and informative report on all used data, parameters and calculations leading to individual results, decomposed as useful for the understanding. The report only contains data, results and analyses pertaining to a single TSO. The confidential report was uploaded in an electronic version to each authorized NRA on the platform.

1.4 Reading guide

1.08 Chapter 2 provides a short summary of the project organization, followed by Chapter 3 outlining the data collection and validation process. Chapter 4 covers the full methodology for the activity analysis, the standardization of operating and capital expenditure, the benchmarking method, the model specification and the outlier detection. Chapter 5 reports on the results for the final model, including a robustness analysis. The results of the complementary survey on service quality are summarized in Chapter 6. Chapter 7 closes the study with a discussion of main findings, some perspectives and future work.

1.5 Appendix

1.09 The Appendix is released as a separate file. It contains the following documentation, not covered in the report but essential for the comprehension of the project:

A. Electricity asset reporting guide, 2018-03-08

B. Financial reporting guide, 2018-03-08

C. Special conditions reporting guide, 2018-09-13

D. Method to treat upgrading, refurbishing and rehabilitation of assets, 2017-12-19

E. Modelling opening balances and missing initial investments, 2018-01-11

F. Norm Grid Development Technical Report, 2019-02-27 V1.3

2. Benchmarking process

In this Chapter the benchmarking process is summarized, including list of participants and the different points of interaction in the project.

2.1 Project phases

2.01 The project is organized into three phases as in Figure 2-1, described below. The time axis in this picture refers to the original plan. Dates mentioned below Figure 2-1 are realized dates.

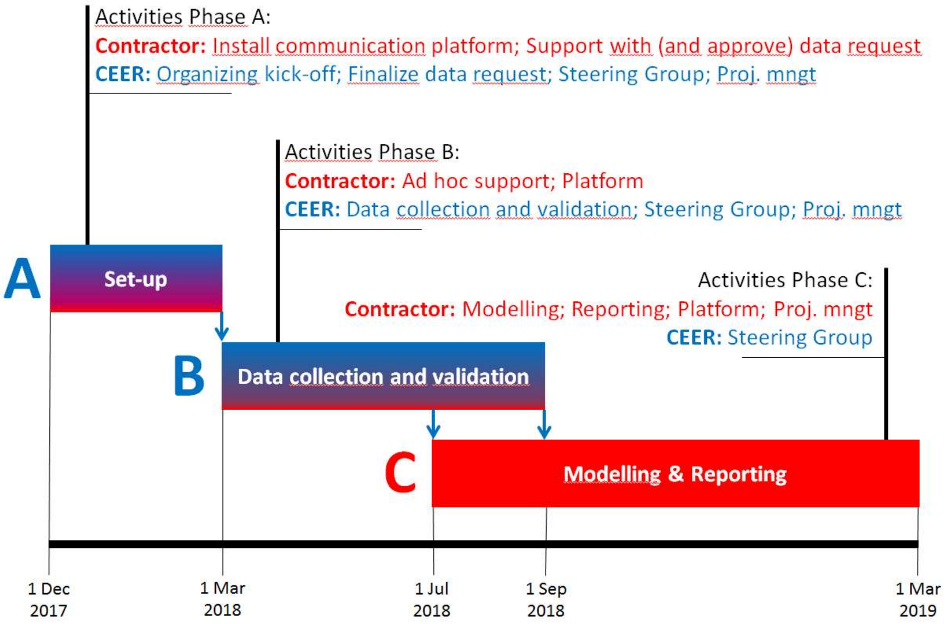

Figure 2-1 Project phases (original dates)

Phase A

2.02 The initial phase is devoted to the launch, detailed planning and preparation for the operational part of the project in the next two phases.

2.03 Duration: 01/12/2017 – 28/02/2018

2.04 Key events:

1) Project management setup
2) Kick off workshop W1
3) Project platform setup
4) Revision and final release of data definition guides and Excel templates

Phase B

2.05 The data collection and validation phase is mainly in the hands of CEER and the NRAs, the consultant act as support and coordinator of the project platform.

2.06 Duration: 01/03/2018 – 30/08/2018

2.07 Key events:

1) Data collection
2) Data validation (NRA)
3) Cross validation of data (consultant)
4) Workshop W2 on data collection
5) Collection of environmental public parameters (consultant)

Phase C

2.08 The last project phase contains the model specification, verification, calculations, outlier identification, sensitivity analyses, documentation, presentation and report editing for CEER and the individual NRAs.

2.09 Duration: 01/09/2018 – 30/06/2019

2.10 Key events:

1) NormGrid development
2) Workshop W3 on NormGrid models and environmental factors
3) Model specification
4) Workshop W4 on model specification
5) Release of individual TSO-specific data sheets pre-run
6) Efficiency analyses
7) Robustness analyses
8) Workshop W5 on final results
9) Editing of final report
10) Editing of individual TSO-specific score sheet

2.2 Project Team assignments

2.11 The consultant is organized in four teams (CENTRAL, ECON, TECH-GAS, TECH-ELEC). The Sumicsid project members include Prof.dr. AGRELL and Prof. dr. BOGETOFT, with a long experience in methodological and applied benchmarking of energy networks, as well as Dr. Ir DEUSE, international expert engineer in electricity, respectively, all with extensive experience in transmission system analysis and benchmarking.

2.3 Project documentation

2.12 The documentation for the project, data calls, instructions and workshop material as well as methodological notes, were published at a project platform only. Likewise, all data and validation material were up- and downloaded from the project platform, avoiding versioning and security problems associated with email. The platform contained private and public areas for all, electricity and gas transmission operators, respectively.

2.13 The project initially aimed at transparency for, at least, aggregate data and results. However, no consensus could be reached among the TSO participants to share data generally in the project. In consequence, all detailed data and results were disclosed uniquely to the participating TSO and their respective NRA.

2.4 Workshops

2.14 Since for an important part the project is focused at TSO-NRA interaction, a number of workshops were organized (cf. Table 2-1). All project participants, TSOs and NRAs, were invited to the workshops, from which all documentation and minutes were published on the project platform.

Table 2-1 Project workshops ELEC

Workshop	Phase	Date
W1 Kickoff	A	2018-01-15
W2 Method, data validation	B	2018-04-25
W3 Normgrid and environment	C	2018-10-10
W4 Model specification	C	2018-11-27
W5 Final results	C	2019-04-04

2.5 Project participants

2.15 The following TSOs and NRAs took part in the project (cf. Table 2-2):

Table 2-2 TCB18 participants ELEC.

TSO	Country	NRA
ADMIE	GR	RAE
APG	AT	E-Control
AST	LV	PUC
Elering	EE	ECA
ELES	SI	EA
Energinet.dk	DK	DUR
Fingrid	FI	EV
Litgrid	LT	NCC
NGET	UK	OFGEM
REE	ES	CNMC
REN	PT	ERSE
SHETL	UK	OFGEM
SP	UK	OFGEM
Statnett	NO	NVE
Svenska Kraftnät	SE	EI
TenneT	NL	ACM
TenneT DE	DE	BnetzA

3. Data collection

In this chapter, the data collection and the data validation process are discussed.

3.1 Procedure (guide and collection)

3.01 For TCB18 data definition guides, one for asset data (Appendix A) and one for financial data (Appendix B), were developed in a separate project that preceded TCB18. That preceding project started in February 2017 and ended about six weeks after the kick off of TCB18 (so there was actually a slight overlap). Part of that were two workshops, one in May 2017 (W0a) and one in October 2017 (W0b).

3.02 TSOs received the final data definition guides (Appendix A and B) early March 2018 and were asked to deliver data in the middle of May 2018. In that period CEER organized the second TCB18 workshop (W2), dedicated to data collection. That workshop was meant to discuss the progress of data collection by TSOs and to identify and solve issues with it. NRAs had the time to validate TSO data until the end of June. After the second TCB18 workshop CEER decided to extend "softly" the deadline for delivering data by TSOs to the end of June. By "softly" was meant that TSOs were asked to agree with their NRAs a time path for delivering data in such a way that by the end of June the data was delivered by the TSOs and validated by the NRAs. Eventually, most data was delivered and validated nationally on time. However, not for all TSOs, imposing some stress on subsequent stages of TCB18.

3.2 Data quality strategy

3.03 For TCB18 CEER developed and laid down (workshop W2) a clear strategy for safeguarding the quality of the benchmark data that enters the benchmark, see Figure 3-1 below.

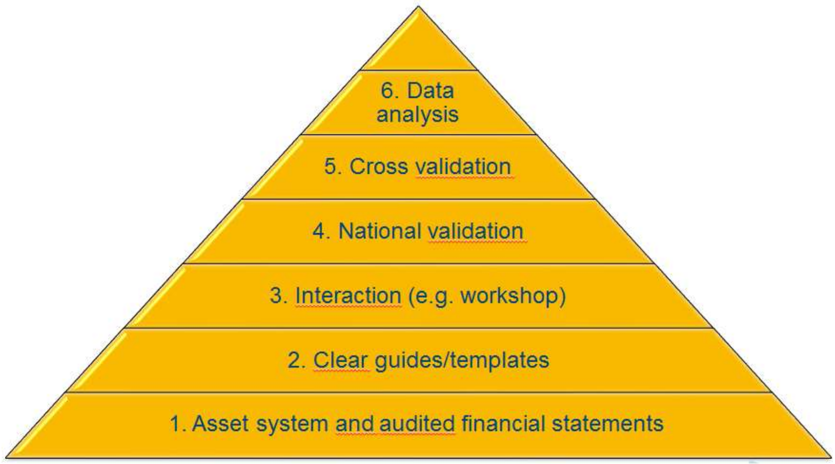

Figure 3-1 Data quality strategy.

3.04 The data quality strategy consists of six layers:

1) The first- or base-layer is the asset system and audited financial statements of TSOs. The data quality strategy is founded on the principal that TSOs have a proper asset system and audited financial statements.
2) The second layer consists of reporting guides and templates, see Paragraph 3.1. For a year CEER, TSOs, and the consultant have interactively worked on clear data definitions to translate the base-layer (asset system and audited financial statements) into benchmark data.
3) In all steps of the process there was interaction between TSOs, NRAs and the consultant, notably through many workshops. The interaction helped in the correct interpretation of definitions among participating TSOs and NRAs.
4) After data collection, national validation at NRA level has been performed. The goal of national validation is to assure that data is complete, consistent, correct and plausible.
5) After National validation, cross validation was done by the consultant. The goal of cross validation is that remaining misinterpretation of definitions amongst countries are detected and corrected for. In an ideal world it should not be necessary, but practice is unruly and a cross validation is necessary.
6) Finally, data analysis has been done by Sumicsid to develop a benchmark model. This is seen as part of the data quality strategy as data analysis may reveal errors in the data that was not picked up by national or cross validation. So actually, the validation (i.e. the previous layer) did not have a well-defined ending, it continued as long as the analysis and modelling were in progress.

3.05 TSOs were not asked to audit their data formally by an independent auditor. A first reason for that is that the data definitions take the audited annual accounts as starting point. Furthermore, NRAs will also check data against sources like regulatory data, which are often audited and validated before. Also, an audit often focuses on just a part of the data, mostly the financial accounts. So, an explicit audit on the benchmark data for each TSO was not seen as a necessary part of the data quality strategy.

3.06 Final data checks were done in March/April 2019. All TSOs and NRAs received a dump of asset and financial files that they could check on missing or incorrect data. For many TSOs a few final corrections have been made, leading to data sets of good quality.

3.07 Although no strategy will be fully safe, CEER believes that its structured approach was indeed vital in securing a successful benchmark project.

3.3 Environmental data

3.08 The TCB18 benchmark model addresses several environmental factors, like landuse, slope, humidity etc. To do this data is required about such factors. In E2GAS (CEER gas TSO benchmark 2015/2016) this data was collected by asking TSOs to specify the operating conditions at asset level. The main drawback of that approach was that it stimulated strategic reporting. Also, item-wise reporting assumed all environmental effects and their combinations to be known beforehand, making statistical analysis difficult and the results too dependent on the engineering assumptions. Finally, the capacity and resources necessary from the TSOs to estimate the different factors vary and depend on the importance assigned to the benchmarking results in the respective countries. All these reasons made the E2GAS approach less attractive.

3.09 In E3GRID, the consultants collected some aggregate indicators at country level, e.g. population density, that were used as proxies for environmental complexities. This approach is exogenous and "equitable", but the resulting adjustment for environmental conditions is rather crude, prompting various technical measures in the benchmarking techniques to avoid absurd results. The E3GRID approach was therefore judged to be unsatisfactory for the new benchmarking.

3.10 TCB18 is not only a one-shot project to arrive at a unique model. It is one step towards a structured development of periodic regulatory benchmarking. As such, the priority is also to provide structurally and incentive-analytically sound solutions for future repetitions. An ideal solution would be to organize external collection of all environmental conditions from public established databases based on the actual asset locations for all participants. In subsequent runs these reporting restrictions and the format for delivery and processing of environmental data could be developed as an add-on project to TCB18, leading to several interesting applications also for the TSOs own use. Combining open databases for landuse, soil type, humidity, topography et.c. into a platform where the environmental complexity could be objectively assessed without any manual intervention by operators or regulators would be a desired outcome of this process.

3.11 The process proceeded initially by an independent identification of the relevant environmental factors by type of energy (gas, electricity), the assets concerned by factor, the economic rationale of impact and the hypothesized magnitude (See Appendix F). The consultants thereafter identified and collected the corresponding data items from the available data bases, subjecting the data to statistical tests for impact using the reported data.

3.12 The sources in Table 3-1 were used for analysis, in particular the Copernicus and CORINE GIS-based metrics derived for each TSO.

Table 3-1 Data sources for environmental factors.

Condition	Source	Granularity
Landuse (agricultural, urban, …)	EUROSTAT	Country
Landuse (type of use)	CORINE (GIS)	TSO
Vegetation (shrubs, grass, …)	EUROSTAT	Country
Area (forests, lakes, mountains, ...)	EUROSTAT, OECD	Country
Climate (wind, icing, salt, extreme temperature)	WeatherOnline, Geographic	City
Road infrastructure	OECD	Country
Topography (ruggedness, coastal area)	Puga et al. (2012)	Country
Topography (slope)	Copernicus (GIS)	TSO
Humidity conditions (wetness, water)	Copernicus (GIS)	TSO
Soil conditions (subsurface features)	Copernicus (GIS)	TSO

3.13 The granularity of the GIS-based data is very good. As an example, the slope factor (a key factor in the construction costs for major infrastructure projects over land) is estimated in Copernicus from cells with a side of 25m, providing height data with a vertical accuracy of 7m, based on satellite imagery and geographical modelling. The data allows detailed calculations of the share of any area within given ranges of slopes, defining the concepts as 'hilly', 'undulating', 'mountainous' etc. objectively and with high scientific validity.

3.4 Special conditions

3.14 During the project TSOs were given an opportunity to signal conditions that are not addressed by the benchmark model, but they think should have been. Such conditions are referred to as special conditions and may call for correction of benchmarked scope or data, or the benchmark model. The concept of special conditions evolves from the concept of so-called Z-factors in previous CEER benchmarks.

3.15 Defining and implementing special conditions is meant to get closer to the purpose of the benchmark, i.e. to define best practices. As all TSOs in the sample will be related to frontier companies, it is therefore important that special conditions should only be labelled as such if they stand a number of criteria:

Complementarity

3.16 This criterion is meant to distinct conditions that are already sufficiently dealt with by the benchmark model from conditions that are not and may need complementary treatment. For example, if the condition can be dealt with by building additional standard assets, and if the model would "credit" TSOs for their asset base, then the condition is likely to be already considered sufficiently by the model. There can actually be two reasons for complementary treatment. First of all, this could be the case if the benchmark model is insufficiently specified. A typical example of complementary treatment in such case would be the change or addition of a modelling parameter. Secondly, complementary treatment may be called for if the claimed condition is something very specific that only one or few TSOs in the sample have to live with, i.e. the condition is relatively unique to the claimant. At all times and most importantly, complementary treatment will only be done if doing so fits the purpose of the benchmark.

Objectification

3.17 A special condition is something that, so to say, overcomes a TSO, i.e. it can reasonably not be held against the TSO and this should not be arguable. Special conditions must not be defined in terms of the (subjective) strategy to deal with the condition. So a claim cannot be formulated like "we do A because of condition C", because A would only refer to a choice made by the TSO that may be up for efficiency analysis. Instead a claim should be formatted like "we are faced with condition C and dealing with it inevitably comes with a disadvantage (compared to not having C)." So, both the condition C and the unavoidability of a disadvantage must fully and inarguably be beyond control of the TSO. Objectivity also implies that the condition is conceptually simple, obvious, and transparent, even to less informed public.

Durability

3.18 Incidents do not qualify as special conditions, think e.g. of a flooding in a certain year. Instead, special conditions are supposed either to exist over a substantial part of the reporting period, i.e. many years, or to exist for many years in the future impacting operations in the past. No explicit norm for this has been set as it may depend on the precise nature of the condition (geographical, technical, economical, etc.). At any rate, this criterion is meant to separate structural circumstances from incidents.

Materiality

3.19 Special conditions can only be recognized as such if they come with a well-defined and significant cost impact. The cost impact of a special condition is defined as the minimum unavoidable cost to deal with the condition. This is what is seen as the value of the claim. Put differently, the value of the claim is the cost difference between the lowest cost alternative to deal with the condition (this is not per se the alternative that is actually implemented) and the cost that would have been made if the condition would not exist. At any rate, the cost impact of a special condition must be clearly quantifiable. If quantification is ambiguous or poorly documented, it will be difficult to correct in the benchmark for the condition. Moreover, it would signal that the condition does not have (had) the explicit attention of management as such, which makes the condition being a special one less credible. Also, the (monetary) value of the claim must be significant, i.e. it must be big enough to significantly impact the outcome of the benchmark. A soft norm for this is about 5 percent of the benchmarked gross investment stream of the claimant or, if the claim is about expenses only, about 5 percent of its benchmarked expenses. This is important to avoid erosion of the best practice frontier by relatively small peculiarities of which all TSOs will have some, some fortunately, some unfortunately.

3.20 These criteria are cumulative, forming a firewall to improper claims in order to protect the hygiene of the best practice frontier, which is in the interest of all TSOs. Individual interests can only impact the benchmark if this is reasonable to all. Nevertheless, as the benchmark can be used in regulation, individual interests are of course quite relevant, think of a severe unfortunate incident in the reference year, strong political pressure on the TSO, legacy, or regulatory decisions. However, such cases boil down to interpretation of an individual benchmark score, which is a national affair between individual NRAs and TSOs, just like with implementation of benchmark results afterwards in regulatory decisions. So it is important to bear in mind that there is a cut-off point where international benchmarking stops and national interpretation and implementation starts. The benchmark model defines that point and the criteria for special conditions are instrumental to that.

3.21 The text in the above was part of a special conditions reporting guide of which a first draft was consulted in July 2018 (Appendix C). The final version of September 2018 was almost the same as the draft. TSOs were given time until early January 2019 to submit claims.

3.22 8 TSOs submitted in total 25 claims of which 16 were rejected by the PSG and 9 were put under investigation. The rejected claims, including the reason for rejection read:

Table 3-2 Operator specific claims rejected with motivation.

TSO	Claim	Grounds for rejection
TenneT	TenneT is required to build Wintrack towers to optimize for magnetic fields and to fit in the landscape.	The submitted claims show that all TSOs face certain obligations, even though this differs countrywise. In fact, also TSOs that did not claim anything in this area face many obligations. Therefore, correcting this only for TSOs that claimed in this area would bias the benchmark result. Also, Wintrack is related to density issues, which will be tested for in model development. Also, see the claim from Energinet, showing commonality to some extent.
TenneT	Costs for brownfield (replacement) investment are higher that greenfield.	Age will be addressed in the model. The Norwegian TSO also claims that newer construction projects are more expensive than older ones. The claim is not substantiated.
Energinet	Energinet is required to build the 400 kV Kasso-Tjele line with new design towers.	The submitted claims show that all TSOs face certain obligations, even though this differs countrywise. In fact, also TSOs that did not claim anything in this area face many obligations. Therefore, correcting this only for TSOs that claimed in this area would bias the benchmark result. Also, new design towers relate to density issues, which will be tested for in model development. See a claim from TenneT as well, showing commonality to some extent.
TenneT DE	DLR and 80 degrees retrofitting increases capacity without building new lines.	Not material and also not unique, but it could be something for future benchmarks. CEER will consider in future benchmarks to differentiate between nominal and operational capacity.
TenneT DE	Due to increasing infeed of renewable energy sources (RES), the loading of the grid is higher. To keep the stability of the system, it is necessary to have short error clarifications times. This is a prerequisite to use DLR and integrate RES. For that a full redundant protection scheme as well as respective telecommunication connections was to be built.	Not material and also not unique. Related to another claim of TenneT DE.

TenneT DE	Risks associated with blackout led to emergency power diesel aggregates on all substations.	Not material. This claim is also quite common, showing that all TSOs need to secure supply as part of their business. Claims of this kind do not convince that obligations are much more severe in some country than in others. Diesel backup generators also appear in other countries.
TenneT DE	Rebuilding of control technique to ensure stability of the system.	Not material. This is also regarded managerial, hence not an exogenous circumstance.
APG	OPEX labour costs differ in Europe.	Addressed in benchmark model.
APG	OPEX price levels differ in Europe.	Addressed in benchmark model.
APG	CAPEX for lines before Austria joined EU in 1995 was 20% higher.	The benchmark model accounts for differences in price levels.
APG	CAPEX labour costs differ in Europe.	Addressed in sensitivity analysis for model.
APG	CAPEX price levels differ in Europe, OECD price levels should be used.	The benchmark model accounts for differences in price levels.
Eles	Obligations for labour lead to 5% higher expenses.	Addressed in model. Also, the obligation mentioned holds in more countries.
Statnett	Regulator imposes system operations tasks for the distribution grid.	Reported under activity S which will not be benchmarked in TCB18.
Statnett	Over time standards and demands for (a.o.) safety and environment become stricter leading to higher CAPEX.	This is a common phenomenon, also claimed by another TSO. Also, the benchmark model addresses age effects.
REE	Obligations to ensure safe fire line require frequent inspection, maintenance and vegetation pruning.	Not unique, multiple TSOs face similar obligations

3.23 Claims that were put under investigation are listed in Table 3-3:

Table 3-3 Investigated operator-specific claims.

TSO	Claim	Consideration in model
TenneT	Soil conditions require drainage of soil and deep foundations of substations and towers.	Soil conditions were part of the environmental conditions tested on GIS data for inclusion. Tower design explicitly included as output variable.
TenneT	High speed winds and icing requirements due to proximity to the coast require heavier towers and frequent painting.	Icing conditions tested for inclusion, not selected and not significant in second-stage analyses. Wind conditions not well defined for the cost functions (Appendix F), but tower desing included as output.
TenneT	Higher population density leads to higher cost.	Population density considered through landuse data at GIS-level, output variable.
TenneT DE	Deep foundations of substations and towers needed.	See soil conditions.
TenneT DE	Icing requirements require stronger towers.	Icing tested and not included, not significantly differentiating among TSOs.
APG	Average Britain/US NormGrid weights for lines do not consider Austrian topography.	Average weights are corrected in the model for landtype conditions at GIS level. In addition, tower design and routing complexity are considered.
Statnett	Wind and ice, topography and accessibility lead to a classification in easy, normal and difficult lines.	The three classes are not exhaustive for the study, landuse and routing complxxity are considered, icing is not included, wind included only through tower material choice.
IPTO	Difficult topography.	Topography considered through landuse and tower/routing design outputs.
REE	High speed winds and icing requirements due to proximity to the coast require frequent inspection, maintenance and painting.	Landuse and routing complxxity are considered, icing is not included, wind included only through tower material choice.

3.24 Putting the claims in Table 3-3 under investigation means that the impact of the claim was tested for in the cost driver analysis. As defined, none of the claims were defined as separate cost drivers, but rather captured by correlations to other parameters. With the exception of wind, all other factors were tested on relevant data. The consideration of average or worst case wind data was not prescribed by the engineering analysis at this stage.

4. Methodology

This Chapter is devoted to the discussion of the methodological approach that has been used in the TSO benchmarking, including the important preparation in terms of activity analysis, cost standardization, asset aggregation and correction for structural comparability. The Chapter then addresses model specification and method choice.

4.1 Background

4.01 The benchmarking model is pivotal in incentive-based regulation of natural monopolies. By essence, benchmarking is a relative performance evaluation. The performance of a TSO is compared against the actual performance of other TSOs rather than against what is theoretically possible. In this way, benchmarking substitutes for real market competition.

4.02 Of course, the extent to which a regulator can rely on such pseudo competition depends on the quality of the benchmarking model. This means that there is no simple and mechanical formula translating the benchmarking results into for example revenue caps. Rather, regulatory discretion – or explicit or implicit negotiations between the regulator, the industry and other interest groups – is called for.

4.2 Steps in a benchmarking study

4.03 The development of a regulatory benchmarking model is a considerable task due to the diversity of the TSOs involved and the potential economic consequences of the models. Some of the important steps in model development are:

4.04 **Choice of variable standardizations:** Choices of accounting standards, cost allocation rules, in/out of scope rules, asset definitions and operating standards are necessary to ensure a good data set from TSOs with different internal practices.

4.05 **Choice of variable aggregations:** Choices of aggregation parameters, such as interest and inflation rates, for the calculation of standardized capital costs and the search for relevant combined cost drivers, using, for example, engineering models, are necessary to reduce the dimensionality of potentially relevant data.

4.06 **Initial data cleaning:** Data collection is an iterative process where definitions are likely to be adjusted and refined and where collected data is constantly monitored by comparing simple Key Performance Indicators (KPIs) across TSOs and using more advanced econometric outlier - detection methods.

4.07 **Average model specification:** To complement expert and engineering model results, econometric model specification methods are used to investigate which cost drivers best explain cost and how many cost drivers are necessary.

4.08 **Frontier model estimations:** To determine the relevant DEA (and depending on data availability SFA) models, they must be estimated, evaluated and tested on full-scale data sets. The starting point is the cost drivers derived from the model specification stage, but the role and significance of these cost drivers must be examined in the frontier models, and alternative specifications derived from using alternative substitutes for the cost drivers must be investigated, taking into account the outlier-detecting mechanisms.

4.09 **Model validation:** Extensive second-stage analyses shall be undertaken to see if any of the non-included variables should be included. The second-stage analyses are typically done using graphical inspection, non-parametric Kruskal-Wallis tests for ordinal differences and truncated Tobit regressions for cardinal variables. In addition to second stage control for possibly missing variables, it is desirable to perform extensive robustness runs to ensure that the outcome is not too sensitive to the parameters used in the aggregations.

4.10 It is worth emphasizing that model development is not a linear process but rather an iterative one. During the frontier model estimation, for example, we identified extreme observations resulting from a data error not captured by the initial data cleaning. In turn this may lead to renewed data collection and data corrections. Such discoveries make it necessary to redo most steps in an iterative manner.

4.3 Activity analysis and scope

4.11 Benchmarking relies crucially on the structural comparability of the operators constituting the reference set. Differences in structure primarily result from differences in (i) assigned transport tasks, (ii) interfaces with other regulated or non-regulated providers and (iii) asset configuration. The identification of the main functions is the first action in a benchmarking context since different operators cover different functions and therefore cannot be directly compared at an aggregate level. The identification is also crucial since different regulations and usages of the performance evaluations may require different perspectives.

4.12 An electricity TSO performs a range of functions from market facilitation to asset management. The task here is twofold; first to make a systematic and relevant aggregation of the different activities and to map them to existing or obtainable data that could be reliably used in an international benchmarking. Second, the scope must be judged against the types of benchmarking methods and data material realistically available. E.g. if the activity (say planning) yields output for a horizon way beyond the existing data, the activity is not in the relevant scope for a short-term benchmarking.

4.13 The common core task for the electricity TSOs here is defined as providing and operating the assets for transport and transit of energy. More specifically, we focus on (i) transmission using high-voltage overhead lines and cables, (ii) transformation at the high-voltage level interfacing with other grids, generation or distribution system operators, and (iii) activities: grid planning, grid maintenance, and grid operation. Other elements, notably system operations and market facilitation and storage, are out of scope in TCB18. For more discussion of the definition of relevant scope, see the E3GRID study (2013).

4.4 Grid transmission activities

4.14 The fundamental objective of a transmission system operator is to transport energy to interconnected networks, generators, distribution networks and other connected clients.

4.15 By distinguishing activities, the autonomy and independency of an operator may be put in a correct context to enable, among other things, performance assessments. The activities are listed below.

4.16 Note that in previous benchmarking, activities such as Grid construction (C) or Grid financing (F) were listed and defined. In this project, these activities are no longer informative for validation or comparability. In practice, almost all activities of construction are capitalized and the activity has no assets, staff or costs in the accounts of the typical TSO. Likewise, the financial activities related to grid operations are not susceptible to standardization.

4.5 T Transport

4.17 The transport activity includes the operation of the injection, transport and delivery of energy through the transmission system, from defined injection points to connection points interfacing a client, a downstream network, or an interconnection to another transmission network. The transport activity is enabled by the operations of grid assets for transport (lines and transformers for electricity, pipelines and compressors for gas). The transport activity thus comprises the day-to-day activities of real-time flow control, metering and operational control and communication.

4.18 The assets utilized for transport constitute the power system characterizing the TSO. The operational expenses for transport include staffing control centers, inspections, safety and related activities, including direct costs for products and services as well as staff.

4.19 The cost for energy used in transport (covering internal consumption and losses) is reported separately under T to control for structural comparability

4.6 M Grid maintenance

4.20 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 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, and emergency action.

4.21 The activity may have assets (spare parts) and operating costs (direct, staff and outsourced services).

4.7 P Grid planning

4.22 The analysis, planning and drafting of power network 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 European, governmental and regional agencies for preapproval granting.

4.23 Grid planning also covers the general competence acquisition by the TSO to perform system-wide coordination, in line with the IEM directive, the TEN corridors and the associated 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.

4.24 The activity has no assets and operating costs (direct, staff and services). In the case internal planning costs are capitalized, this is noted in the investment stream.

4.8 I Indirect support

4.25 With indirect services, we refer to services related to the general management of the undertaking, the support functions (legal, human resources, regulatory affairs, IT, facilities services etc.) that are not directly assigned to an activity above. Central management, including CEO, Board of directors and equivalent is also explicitly included.

4.26 In principle, the residual assets for a transmission system operator (e.g. office buildings, general infrastructure) could be considered as assets for Indirect support.

4.27 However, to the extent that this entails the incorporation of land, land installations and non-grid buildings in the analysis, all of which are susceptible to be country specific investments, such elements are excluded from the benchmarking.

4.9 S System operations

4.28 Within system operations for electricity transmission, ancillary services are retained as defined in 2009/72/EC and congestion management (compliant with the ENTSO-E classification). Ancillary services include all services related to access to and operation of electricity transmission networks, including balancing.

4.29 ENTSO-E further considers the transparency in data exchange with the purpose of interoperability as a specific point in system operations. In consequence, costs related to this activity per se are to be considered as system operations.

4.30 If part of the services above are delegated to subordinate (regional) transmission coordinators with limited decision rights, the associated costs are included in system operations.

4.31 System operations has no assigned assets, the costs are direct costs for services and staff.

4.10 X Market Facilitation

4.32 Market facilitation includes all direct involvement in energy exchanges through information provision or contractual relationships. This comprises regulated tasks through procurement of renewable power, residual buyer obligations or capacity allocation mechanisms, capacity auctioning mechanisms, and work on coordination of feed-in tariffs.

4.33 The market facilitation activity is composed uniquely of direct expenses related to the contractual relations excluding transport and storage, primarily information costs and energy purchases for other purposes than the consumption in their own grid.

4.34 The activity has no eligible assets and no staff costs.

4.11 TO Offshore transport

4.35 The transport and transit of electricity through offshore assets (i.e. subsea cables and subsea interconnectors, see Asset reporting guide ELEC (Appendix A), art 11, are considered as offshore transmission activities.

4.12 O Other activities

4.36 A TSO may have marginal activities that are not covered by the classification above, such as external operator training, field testing for manufacturers, leasing of land and assets for non-transport use. These activities should be listed, the costs and assets should be specified and excluded from the benchmarking.

4.13 Scope

4.37 Based on the analysis of common factors in cost reporting, the variability and homogeneity of the data and the separability of the activity, it was decided to define the benchmarked scope as the structurally comparable core activities of the transmission operator, i.e. T, M, P, and I (partially), see Figure 4-1 below. Planning (P) was included as it was present in all TSOs and considered as a techno-economic necessity, inseparable from the investment and operational activities.

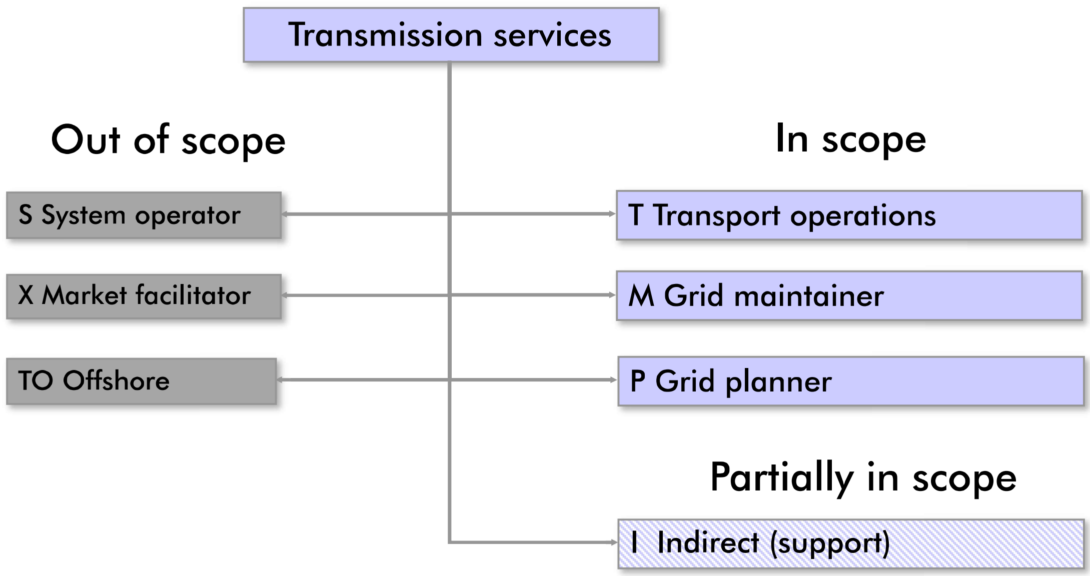

Figure 4-1 Benchmarked actvities and scope.

4.38 To permit a mapping of the P&L onto the activities, the operators also report the activities S, X, TO, and, if applicable, O. These activities are to be validated to avoid cost leakage, but are not in the planned benchmarking scope.

4.14 Cost definitions and standardization

4.39 Benchmarking models can be grouped into two alternative designs with an effect on the scope of the benchmarked costs:

A. A short-run maintenance model, in which the efficiency of the operator is judged-based on the operating expenditures (Opex) incurred relative to the outputs produced, which in this case would be represented by the characteristics of the network as well as the typical customer services.

B. A long-run service model, in which the efficiency of the operator is judged-based on the total cost (Totex) incurred relative to the outputs produced, which in this case would be represented by the services provided by the operator.

4.40 From the point of view of incentive provision, a Totex based approach (B) is usually preferred. It provides incentives for the TSOs to balance Opex and Capex solutions optimally. In this study, the focus is therefore on Totex benchmarking.

4.41 The standardization of costs plays a crucial role in any benchmarking study, especially, when the study is international. Below we discuss the derivations of the benchmarked operating and capital cost, leading to the final benchmarked dependent variable; the benchmarked Totex.

4.15 Benchmarked OPEX

4.42 There are various steps involved in order to derive the respective benchmarked Opex for the benchmarked functions in scope below, see Figure 4-2 below.

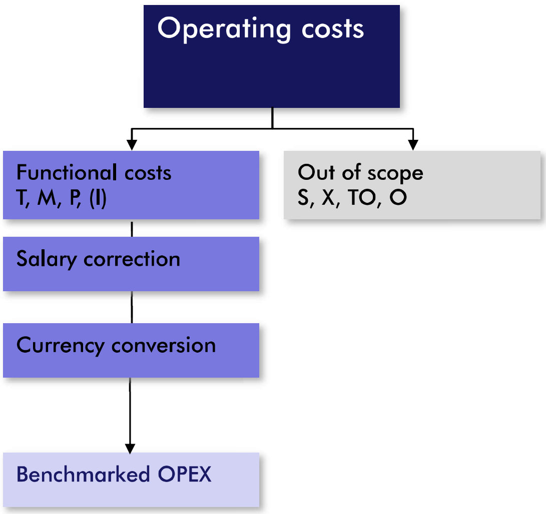

Figure 4-2 Steps in deriving benchmarked OPEX.

4.43 The relevant cost items for OPEX, derived directly from the TSOs' data per activity are added together (cf Cost reporting guide, Appendix B).

4.44 Depreciation of grid related assets is excluded from this list, as this is covered by the benchmarked CAPEX.

4.45 The cost of energy is deducted from benchmarked OPEX at this step.

OPEX: Labor cost adjustments

4.46 In order to make the operating costs comparable between countries a correction for differences in national salary cost levels has been applied. Otherwise TSOs would be held responsible for cost effects, e.g. high wage level, which is not controllable by them.[1] The basis for the labor cost adjustment is the labor cost, not the data collected on FTE (full time equivalent employees) by function, since these data were less reliable.

4.47 The salary adjustment consists of two steps:

1) *Step 1 – adjustment of direct manpower costs* by increasing/decreasing the direct manpower costs of the companies using the respective salary index.
2) *Step 2 – reversal of part of salary* adjustment. Step 1 applies to a gross value, while the Opex entering the benchmarking is a net value after deducting direct revenues (for services outside the scope of the benchmark). Hence, some part of the salary adjustment has to be reversed considering that the share of direct manpower costs is proportionally smaller in the Opex used for benchmarking.

4.48 The correction for systematic salary cost differences can be made by several indexes, see Table 4-1 for those collected and tested in the study. The general indexes, such as the EUROSTAT index for all services (LCIS) correlates poorly to the actual salary differences observed among the TSOs, primarily since the basis for the index involves services not involved in transmission. Figure 4-3 illustrates three indexes, whereof the PLICI index was chosen since its scope (civil engineering services) corresponded the best to the differences between the salaries paid and European average. Compared to previous studies using general indexes, the current approach provides a lower variance in the estimation, better fitting the real differences.

[1] We note that there is some simplification involved in the logic of salary cost adjustment. Had the respective operator truly had lower (or higher) salary cost then it may in practice also have chosen a different mix of production factors - e.g. operate less (or more) capital intensively. However, we do not consider this in the context of salary cost adjustments.

Table 4-1 Labor cost indexes tested (PLICI selected).

Index	Source	Type	Scope
Plits	EUROSTAT	Price level index	Services
Plitg	EUROSTAT	Price level index	Goods
Plico	EUROSTAT	Price level index	Construction
Plici	EUROSTAT	Price level index	Civil eng
Lcis	EUROSTAT	Labor cost index	Services
Lcig	EUROSTAT	Labor cost index	Goods
Lcic2	EUROSTAT	Labor cost index	Construction F
Lciusm	Fed Bank	Purchasing parity	Manufacturing
Coc	EUROSTAT	Price level index	Construction

OPEX: Inflation adjustment

4.49 Opex data has been collected for 2013-2017 (81 observations). Hence, an indexation to a base year is necessary to make the costs comparable over the years. As for CAPEX, the harmonized price index for overall goods (HICPOG) is used, defining 2017 as the base year.

OPEX: Currency conversion

4.50 All national currencies are converted to EUR in 2017 by the average annual exchange rate.

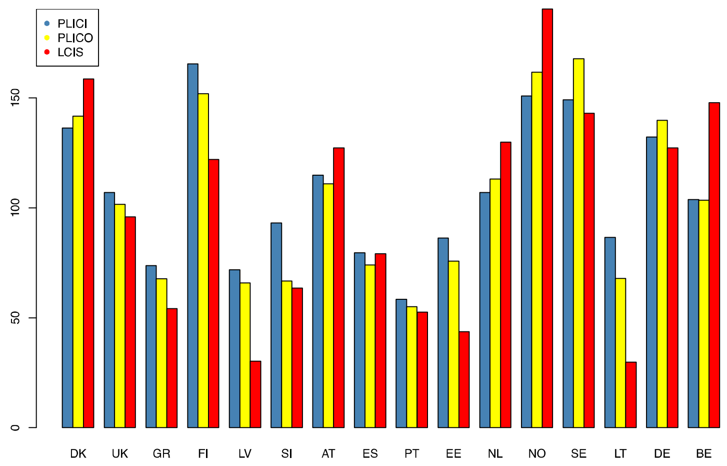

Figure 4-3 Labor cost indexes (EUROSTAT, PLICI=Civil engineering, PLICO = Construction)

4.16 Benchmarked CAPEX

4.51 As accounting procedures, depreciation patterns, asset ages and capital cost calculations differ between countries and sometimes even between operators depending on their ownership structure, the CAPEX needs to be completely rebuilt from the initial investment stream and up. In addition, a real annuity must be used since the application of nominal depreciations (even standardized) would immediately introduce a bias towards late investments. The steps involved in the calculation of benchmarked CAPEX are given in Figure 4-4 below.

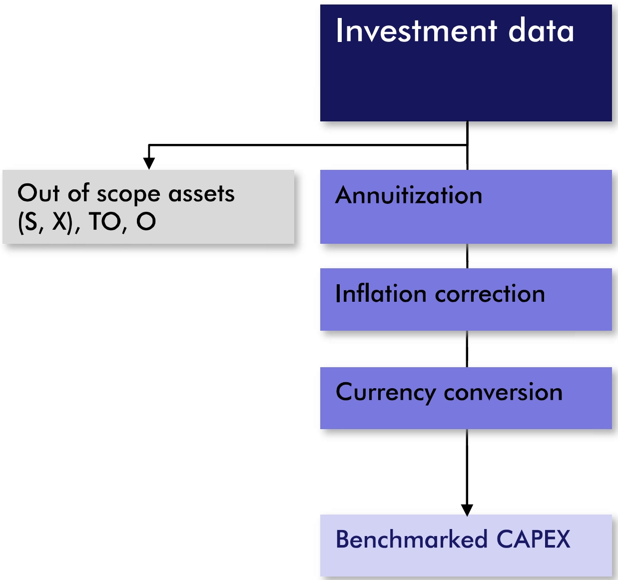

Figure 4-4 Steps in deriving benchmarked CAPEX.

CAPEX: Investment stream data

4.52 The starting point is the full investment stream reported by the operators from 1973 to 2017. Separating assets related to activities out of scope (S, X, TO, O), the residual investment stream is divided by type of asset as:

1) Overhead lines,
2) Cables,
3) Circuit ends,
4) Transformers,
5) Compensating devices,
6) Series compensation,
7) Control centers,
8) Other equipment.

CAPEX: Standard life times

4.53 The differentiation in investment is subject to different techno-economic life times, i.e. the standard real annuities constituting CAPEX.

4.54 The standard life times per asset class are given in below.

Table 4-2 Standard techno-economic life times.

Asset class	Life time (yrs)
Overhead lines	60
Cables	50
Circuit ends	45
Transformers	40
Compensating devices	40
Series compensations	40
Control centers	20
Other assets	20
Equipment	10

4.55 Assets acquired as used of any asset class are collected with original commissioning year or the expected remaining life time. The reported residual life is used for the annuity calculation for used assets, bounded above at the standard life time in Table 4-2 Standard techno-economic life times. for new assets.

CAPEX: upgraded or (significantly) rehabilitated assets

4.56 In case the asset has been significantly rehabilitated the rehabilitation year also needs to be provided. Significant rehabilitation means a large incremental investment into an existing asset without change of any characteristics (i.e. its dimensions and properties). Large is defined as at least 25% of the (real) initial investment. Regular preventive and reactive maintenance, e.g. replacement of system components at or before their lifetime is not counted as a "rehabilitation". See also Appendix D.

4.57 Investments changing the characteristics are considered as "upgrades" and not as rehabilitation.

4.58 Investments linked to upgrading assets that change asset class are counted as new investments. Thus, the original asset is replaced in the asset data with the new asset.

CAPEX: corrections

4.59 The following items are used for the correction of the investment stream prior to the calculation of the annuities:

1) Capitalized costs for out-of-scope assets (see Cost reporting guide, Appendix B)
2) Capitalized costs for financial costs (construction interest)
3) Capitalized taxes, fees and levies
4) Direct subsidies, exceptional direct depreciation and internal labor as direct expense.

4.60 Capitalized cost for out-of-scope assets, financial costs and taxes etc. are deducted from the gross investment stream.

4.61 Direct subsidies and exceptional depreciation are added to the gross investment stream.

CAPEX: Real annuities

4.62 Capex consists of depreciation and a return on capital. The actual investment streams are annuitized using a standard annuity factor $\alpha\ (r,T)$, where r stands for a real interest rate; and T stands for the average life-time of the investments in the respective year, calculated from the shares in art 4.52. The annual investments from the investment stream data are multiplied with the annual standard annuity factor $\alpha\ (r,T)$.

4.63 The numerical values for the annuity factors are provided to each TSO in a specific file.

CAPEX: Real interest rate

4.64 The real interest rate in the TCB18 project is set to 3% for the base run. The sensitivity with respect to this parameter is subject to an analysis reported in art 5.24 below.

CAPEX: Inflation adjustment

4.65 The current 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 and OECD, see Table 4-3. In this study, contrary to earlier projects, a Harmonized Inflation Index for overall goods and services has been used, HICPOG. The index is specifically developed for international comparisons, which is not the case with conventional indexes such as CPI and PPI. This provision is ensured by selecting comparable services and goods for the index, rather than those potentially only being used domestically.

Table 4-3 Inflation correction indexes tested (HICPOG used).

Index	Source	Type	Scope
Cpio	OECD	CPI	General
Cpiw	WorldBank	CPI	General
PPI	OECD	PPI	Producer goods
Hicpg	EUROSTAT	HICP	General
Hicpog	EUROSTAT	HICP	Overall goods
Hicpig	EUROSTAT	HICP	Industrial goods
Hicpmh	EUROSTAT	HICP	Maintenance

4.66 In addition, we have evaluated further indexes (CPI and other harmonized indexes) in the sensitivity analysis. Sector-specific indexes only exist for a handful of countries and require additional assumptions to be used for countries outside of their definition.

CAPEX: Currency conversion

4.67 As for OPEX, all amounts are converted to EUR values in 2017 using the average exchange rates. The exchange rates (annual averages of daily rates) used are provided among the public parameter files.

CAPEX: Old Capex

4.68 Investment stream data prior to 1973 are not required and by default are excluded, since they do not always exist or being of lower quality. However, without any correction this would create a bias towards operators with later opening investments, since these also include earlier assets. Thus, the calculation of the comparable Capex includes a residual element in 2017 corresponding to the pre-1973 assets still in the asset base.

The calculation is equivalent to a Capex Break for 1973, that is the Capex unit cost from 1973 to 2017 is assumed prevail also up until 1973. In this manner, the inclusion of pre-1973 assets do not change the Capex-efficiency, but assures comparability. The calculated value, CapexOld, is capped by the sum of incumbent investments if known and validated. The methodology for the CapexBreak is described in Appendix E.

4.17 Benchmarked TOTEX

4.69 Summing up in Figure 4-5 we obtain the benchmarked Totex as the sum of Opex and Capex where C_{ft} is the total OPEX for firm f and time t after currency correction, I_{fs} is the investment stream for firm f and time s after inflation and currency correction, and $a(r,T)$ is the annuity factor for asset with life time T and real interest rate r.

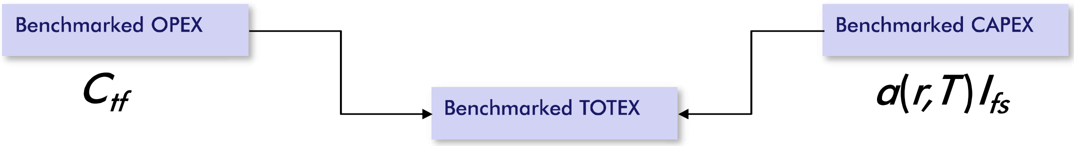

Figure 4-5 Benchmarked Totex = Opex + Capex

4.18 Normalized Grid

4.70 Technically, the relevant scope is provided by an asset base consisting of:

1) Overhead lines,
2) Cables,
3) Circuit ends,
4) Transformers,
5) Compensating devices,
6) Series compensation,
7) Control centers.

4.71 A very detailed dataset was collected for the six asset categories above. Naturally, it does not make sense just to sum the different asset together since they correspond to different dimensions, pressure levels, material choices and capacities. Likewise, the geographical nature of the power system makes it ideal to capture the environmental challenges through the following factors (see Appendix F):

1) Land use
2) Subsurface features
3) Topography

4.72 Based on the data specification, a cost-norm for the construction costs for the standard assets above was developed, including the cost increases due to the environmental factors above. The result is an asset aggregate that we call the Normalized Grid (NormGrid; NG). Note that this detailed cost norm is independent of the actual costs and investments of the individual operator; it provides average costs rather than best-practice (or worst-practice) estimates. However, it is more general than a simple cost catalogue since it provides a complete system of complexity factors that explain the ratio of cost between any two type of assets, irrespective of which year, currency or context it is applied to (within reasonable bounds of course).

4.73 The exact formulae for the NormGrid system are documented in Appendix F, accompanied by an Excel calculator made available for all project participants on the project platform. In addition, workshop W3 was specifically devoted to the development of the norm grid metrics.

4.74 The NormGrid measure for all assets is adjusted for joint ventures by scaling with the share of ownership reported. The same approach is also used for output indicators related to assets in joint ownership, e.g. towers, connection points and power measures.

4.75 The size of the grid as measured by the Normalized Grid (NormGrid; NG) is naturally a key driver for Opex and Capex. The NormGrid is the sum of Capex and Opex components, proportional to the same effects in the total expenditure.

4.76 The NormGrid Opex component is simply the weighted sum of assets in use at a given time, irrespective of their age:

$$NormGrid_{OPEX} = \sum_t \sum_a N_{at} w_a$$

where

N_{at} Number of assets of type a in use, acquired at time t

w_a OPEX weight for assets of type of type a.

4.77 The NormGrid component for Capex below, differs in two respects from the Opex component: first, it only concerns assets that are within their techno-economic life (=their annuity depreciation period), second, the weights are multiplied with the same annuity factors as for the corresponding investments:

$$NormGrid_{CAPEX} = \sum_t \sum_a n_{at} v_a \alpha(r, T_a)$$

where

n_{at} Number of assets of type a, acquired at time t and in prime age.

v_a CAPEX weight for assets of type of type a

r Real interest rate

T_a Techno-economic standard life for assets of type of type a

$\alpha()$ Real annuity function

4.19 Model specification

4.78 Any efficiency comparison should account for differences in the outputs and the structural environment of the companies. A key challenge is to identify a set of variables:

1) that describe the tasks (the cost drivers) that most accurately and comprehensively explain the costs of the TSOs;
2) that affect costs but cannot be controlled by the firm (environmental factors); and
3) for which data can be collected consistently across all firms and with a reasonable effort.

4.79 Conceptually, it is useful to think of the benchmarking model as in Figure 4-6 below. A TSO transforms resources X into services Y. This transformation is affected by the environment Z. The aim of the benchmarking is to evaluate the efficiency of this transformation. The more efficient TSOs are able to provide more services using less resources and in environments that are more difficult.

4.80 The inputs X are typically thought of as Opex, Capex, or Totex. In any benchmarking study and in an international benchmarking study in particular, it requires a considerable effort to make costs comparable. We have found in previous studies that a careful cost reporting guide is important to make sure that out-of-scope is interpreted uniformly, and that differences in depreciation practices, that taxes, land prices, labor prices etc. are neutralized.

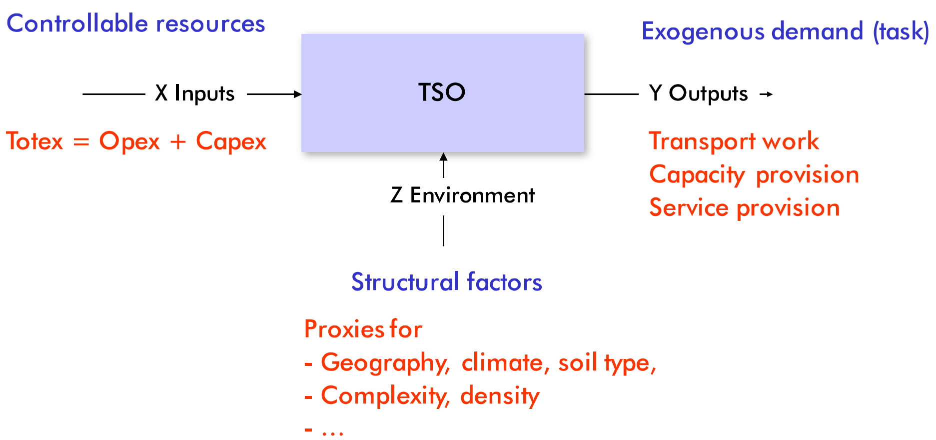

Figure 4-6 Conceptual benchmarking model

4.81 The outputs Y are 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 (peak load, coverage in area etc.) and service provision (number of connections, customers etc.). Ideally, the output measures the services directly. In practice, however, outputs are often substituted by proxies constructed as functions of the assets base, like total circuit length, transformer power, number of connections, etc. One hereby runs the risk that a TSO could play the benchmarking-based regulation by installing unnecessary assets. In practice, however, we have found that this is not a major risk in the early stages of the regulation and that the advantages of using such output indicators outweigh the risk. We shall therefore think more generally of the outputs as the cost drivers.

4.82 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 may often find indicators of geography (topology, obstacles), climate (temperature, humidity, salinity), soil (type, slope, zoning) and density (sprawl, imposed feed-in locations). One challenge with this class of parameters is that they may be difficult to validate statistically in a small data sample. Their role of potential complicating factors will therefore have to be validated by other studies or in a process of individual claims from the TSOs. Another challenge is that in a small dataset, the explicit inclusion of many complicating factors will put pressure on the degrees of freedom in a statistical sense. This is also the approach we have taken in this study. We have used elaborate engineering weight systems of the grid assets to reflect the investment and operating conditions. In this way, Z factors can to a large extent be captured by the traditional Y factors.

4.83 To ensure that the model specification is trustworthy, it is important to decide on some general principles as well as some specific steps. Based on our experience from other projects, we have in this project focused on the following generic criteria:

1) **Exogeneity** – Output and structural parameters should ideally be exogenous, i. e. outside the influence of the TSOs.
2) **Completeness** – The output and structural parameters should ideally cover the tasks of the TSOs under consideration as completely as reasonable.
3) **Operability** – The parameters used must be clearly defined and they should be measurable or quantifiable.
4) **Non-Redundancy** – The parameters should be reduced to the essential aspects, thus avoiding duplication and effects of statistical multi-collinearity and interdependencies that would affect the clear interpretation of results.

4.84 In reality, it is not possible to stick to these principles entirely. In particular, exogeneity must be partly dispensed with since the network assets are endogenous but also in many applications providing good approximations of the exogenous conditions. To rely entirely on exogenous conditions would require a project framework that far exceeds the present both economically and time wise.

4.85 The process of parameter selection combines engineering and statistical analysis. We have in this project used the following steps:

1) **Definition of parameter candidates**. In a first step we established a list of parameter candidates which may have an impact on the costs of TSOs. The relationships between indicators and costs must be plausible from an engineering or business process perspective.
2) **Statistical analysis of parameter candidates**. Statistical analysis was then used to test the hypotheses for cost impacts for different parameter candidates and their combinations. The main advantage of statistical analysis is that it allows us to explore a large number of candidate parameters and to evaluate how they individually and in combination allow us to explain as much as possible of the cost variation.
3) **Plausibility checks of final parameters**. The final parameters from the statistical analysis are finally checked for plausibility. This plausibility check is based *inter alia* on engineering expertise.

4.86 The model specification steps above have supported the model specification process. However, model development in transmission operation benchmarking is not a datamining exercise that follows blindly from statistical analyses aiming at predictive models. It may be that some parameters that help explain average costs have little techno-economic sense or explanatory power in the frontier-based benchmarking model and vice versa. The model specification steps have therefore been combined with careful second stage analysis to ensure that no frontier relevant parameters have been left out.

4.20 Benchmarking methods

4.87 Econometrics has provided a portfolio of techniques to estimate the cost models for networks, illustrated in Table 4-4 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. These techniques are usually considered state of the art and are advocated in regulatory applications provided sufficient data is available.

Table 4-4 Model taxonomy.

	Deterministic	Stochastic
Parametric	Corrected Ordinary Least Square (COLS) Greene (1997), Lovell (1993), Aigner and Chu (1968)	Stochastic Frontier Analysis (SFA) Aigner, Lovell and Schmidt (1977), Battese and Coelli (1992), Coelli, Rao and Battese (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)

4.88 In a study of European electricity TSOs, the number of observations is too small for a full-scale application of SFA as main instrument. We have therefore used DEA as our base estimation approach, in line with regulatory best practice and earlier studies such as E2GAS and E3GRID. The DEA method is by now well established in the scientific literature as well as in regulatory applications, and we shall therefore not provide a theoretical description of it here. Further details are provided in e.g. Bogetoft and Otto (2011)

4.21 Frontier outlier analysis

4.89 *Outlier analysis* consists of screening extreme observations in the frontier model against average performance. Depending on the approach chosen (OLS, DEA, SFA), frontier 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 number of methods (cf. Agrell and Niknazar, 2014).

4.90 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.

Outlier detection in DEA

4.91 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). Outlier DMU may belong to a different technology either by errors in data, or unobserved quantities or qualities for inputs or outputs. The identification of DMUs to check more carefully has used in particular two approaches.

4.92 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.

4.93 Let Ω be the set of n TSO in the data set and k be a potential outlier. Then define $E(h, \Omega)$ be the efficiency of a TSO h when all TSO are used to estimate the technology and let $E(h, \Omega/k)$ be the efficiency when TSO k does not enter the estimation. We can therefore evaluate the impact on the average efficiency by

$$\frac{\sum_{h\in\Omega/k}(E(h,\Omega/k)-1)^2}{\sum_{h\in\Omega/k}(E(h,\Omega)-1)^2}$$

4.94 Large values of this as evaluated in a $F(n\text{-}1,n\text{-}1)$ distribution, cf. Banker (1996), will be an indication that k is an outlier.

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

$$E(k, \Omega/k) > q(0.75) + 1.5(q(0.75) - q(0.25))$$

4.96 where $q(a)$ is the a-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 a super efficiency above 0.75+1.5*(0.75 – 0.25) = 1.5 to classified as an outlier.

4.22 Allocation key for indirect costs

4.97 Several allocation methods were tested for indirect cost onto benchmarked functions. The staff data intensity was considered biased since it excludes external services. Thus, the retained key is based on direct costs, excluding energy and depreciation, for the respective activities, including out-of-scope and non-benchmarked activities.

5. Benchmarking results

This Chapter provides some general and average results from the benchmarking, without providing any information that may lead to the identification of individual operators and their results. The results from the robustness analysis are also included and commented.

5.1 Model specification

5.01 Based on conceptual thinking and a statistical analysis reported during Workshops W4 and W5, the final model specification in the TCB18 project includes three cost drivers as shown in Table 5-1 below.

Table 5-1 Model specification: Final model ELEC.

Variable	Definition
INPUT	
dTotex.cb.hicpog_plici	Totex excl energy, inflation index HICPOG, labor cost adjusted in OPEX with PLICI
OUTPUT	
yNG_yArea	NormGrid assets weighted by landuse area yArea (% of service area) x complexity factors per class
yTransformers_power	Total installed transformer power (MW)
yLines.share_steel_angle_mesum	Total line length, weighted by share of angular towers x share of steel towers

Input in the model is total expenditure (Totex). It is calculated as standardized capital costs using real annuities and after correcting for inflation and currency differences plus standardized operating costs excluding cost of energy, out-of-scope activities. See the explicit formula in Chapter 4 on methods. Labor cost expenditures in Opex are adjusted to average European costs by the PLICI labor cost index. The final model is using three outputs: normalized grid (weighted sum of all grid components as explained in section 4.18), the landuse area share with complexity factors, the total capacity (measured as transformer power) and the length weighted with angular (routing complexity) and steel share (equipment standards). These parameters capture both the investment (capital expenditure) dimension through the normalized grid and the capacity and the operating cost dimension through the routing complexity parameter, leading to good explanatory results for the average cost in the sample. In general, the strongest candidate in the frontier models is the normalized grid. The next strongest cost driver candidate is the landuse dimension, highly significant with respect to both density, environmental and operational complexities. Thereafter follows the overhead lines, irrespective of age and capacity, representing the routing complexity. Finally, the transformer power completes the model with the capacity provision dimension. Together the factors form a very strong explanatory base for the transmission system operators.

5.02 An initial proposal presented at Workshop W5 with a parameter for steel towers to capture the complexity from slope, soil and coastal conditions. Following the discussions with project participants at the workshop and additional techno-economic analysis, the new parameter **yLines.share_steel_angle_mesum** was developed, reflecting the environmental dimensions of density (routing complexity through angular tower incidence), soil, slope and salinity conditions (proportion of steel towers) weighted with the total circuit length (no distinction in capacity or age). In this way, a potential problem of tower distance vs tower reinforcement has been avoided.

5.03 The final model resembles the model from e3GRID 2013[2], also a three-parameter model (Normalized grid, lineweigthed angular towers, densely populated area), but with several refinements. First, the normalized grid in TCB18 takes explicitly into account the landuse and density factors through a detailed GIS assessment (CORINE) by TSO, which was not yet available in 2013. Second, as a consequence the pure 'density' parameter in e3GRID is redundant by inclusion of the landuse area directly in the normgrid parameter. Third, the routing complexity parameter (angular towers over lines) is enhanced in TCB18 with the material choice information, reflecting slope, infrastructure and soil concerns limiting the use of low-cost options. Fourth, the capacity provision dimension that was missing in e3GRID is addressed with a parameter (transformer power) that is explicitly related to the transmission capacity of the system. The logic of the model specification with respect to the earlier categories is illustrated in Figure 5-1 below.

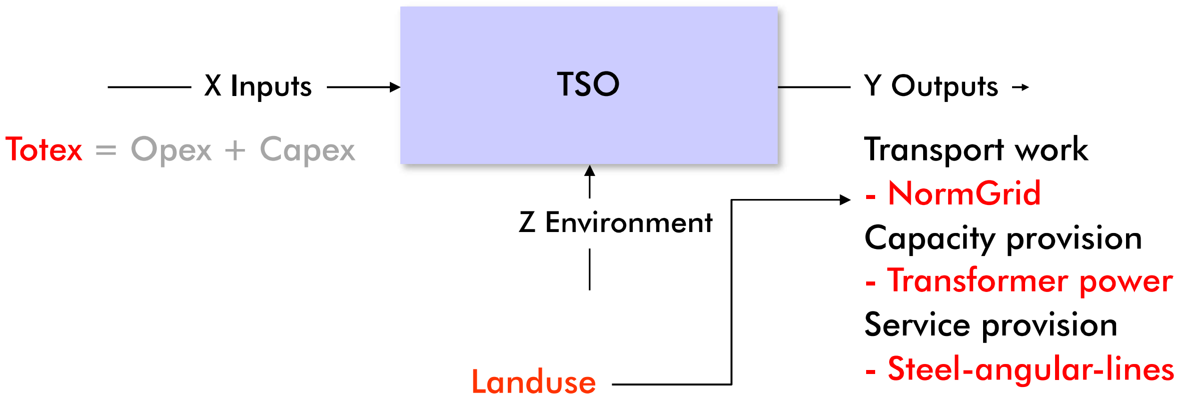

Figure 5-1 Final ELEC model with service categories.

yNormGrid_yArea

5.04 The NormGrid provides a Totex-relevant proxy for the total power system, summing all relevant assets with weights corresponding to their Capex and Opex impact. As documented in the engineering study (Appendix F), the major environmental impact arises from the installations with spatial impact, over or below ground. These factors include land use type, topography (slope), vegetation type, soil humidity, subsurface features (rockiness, stones), extreme temperatures and salinity. Extensive statistical tests revealed correlations and interaction between several of the factors, e.g. vegetation and landuse type, subsurface features and topography. The most important factor for electricity was landuse categories (area measures), relating to costs of construction (reinforcements, site access) and to operation (maintenance access). This is in fact consistent with the earlier results highlighting infrastructure density as a major factor, but in addition it addresses the costs incurred through other factors (slope, subsoil) when operating in specific terrain (forest, mountains). Most other factors, correlate with the normalized grid landuse-weighted parameter. Thus, this parameter was chosen as the

[2] yNormGrid, yLines.share.angular.sum, densly populated area.

primary variable, explaining by itself over 90% of the variance in Totex in robust regression (cf. Table 5-3 below).

yTransformer_power

5.05 Coming out as a strong complement to the first NormGrid parameter, the total transformer power is an evident indicator in the category for capacity provision. The total installed power is not identical to the NormGrid component of the same type, since it takes the physical measure (MW) independent of age and equipment standard, creating a large range of variety in the asset management impact. As other parameters, the consideration of joint ventures is made through a correction by the ownership data. This variable is frequently used in international benchmarking, it is stable and robust, corresponding to an easily observable capacity measure.

yLines.share_steel_angle_mesum

5.06 In addition to the environmental factors previously listed for application to NormGrid categories, the electricity power system has particular challenges related to infrastructure crossings, natural impediments and urban sprawl, forcing the routes to take longer paths. This interesting aspect comes out as highly explanatory, implemented as a weighted sum of circuit length and the share of angular towers. The intuition for the parameter, already present in E3GRID, is that angular towers are required whenever a transmission line needs to deviate from a straight route. As angular towers need to sustain higher (lateral) forces, they require more material and are thus more expensive. In addition, this parameter may also capture planning constraints, difficulty in getting wayleaves for the otherwise optimal route. Therefore, the value of weighted angular towers can be interpreted as a proxy parameter representing the cost impact of topography or high population and/or load density. However, statistical results prompted a further extension of the parameter to integrate the material choice in the towers. This aspect came out empirically already in E3GRID 2009 as an explicative factor for outliers; the low-cost grids had both a higher incidence of wooden, cable-stayed towers and a lower complexity in terms of angular towers. Additional information shows that population density and proximity to infrastructure influence the choice of tower type to higher, access-protected and remotely monitored installations. Thus, the final parameter was developed as the linelength weighted with both the share of angular towers and the share of steel towers. This parameter complements the first landuse-controlled parameter in that it also takes in topology concerns, influencing the reinforcement, as well as infrastructure and population.

5.2 Summary statistics

5.07 Summary statistics of the costs and cost drivers in the base model are shown in Table 5-2 below. (Note that range values cannot be provided for confidentiality reasons). Q1 denotes first quartile, Q3 third quartile and Q2 the median.

Table 5-2 Summary statistics of model variables (2013-2017, full sample, *n* = 81)

Variable	Mean	Q1	Q2 (median)	Q3
dTotex.cb.hicpog_plici	2.723E+08	6.312E+07	1.538E+08	3.039E+08
yNG_yArea	2.932E+08	8.695E+07	2.449E+08	3.390E+08
yTransformers_power	43,102	12,343	25,754	39,990
yLines.share_steel_angle_mesum	1,772	678	1,286	1,752

5.08 We see that the electricity TSOs in the sample vary in terms of size. The two largest electricity TSOs are approximately twice as large as the third biggest TSO. Also, we see that the mean values exceed the median values. This reflects that the size distributions have a relatively long right tail.

5.09 To get an initial understanding also of the ability of these cost drivers to explain the variation in average costs together and individually, Table 5-3 below shows the adjusted R2 (the conventional measure of regression fit) of three ordinary regression models with 1, 2 and 3 cost drivers. We see that the adjusted R2 of a model with only **yNG_yArea** is 95%. Adding **yTransformer_power** as a cost driver brings us to an adjusted R2 of 97%. Finally, when we add also **yLines.share_steel_angle_mesum**, the adjusted R2 becomes 97.8%. No TSOs were identified as statistical outliers in the two and three-parameter regressions in this example, whereas two TSOs fell out as statistical outliers in the NormGrid-only model. The number of parameters (3) in the model is adequate also with respect to the number of observations in the sample for 2017 (17 TSO) according to the convention of 3(#inputs+#outputs), i.e. 3*4=12 here.

Table 5-3 Explanatory power (adjusted R2) for 1, 2 and 3-variable models, robust regressions, *n*=81.

Number of variables	Cost driver(s)	Adjusted R2
1	yNG_yArea	0.950
2	yNG_yArea + yTransformer_power	0.970
3	yNG_yArea + yTransformer_power + yLines.share_steel_angle_mesum	0.978

Outliers

5.10 The analyses of the raw data as well as the analysis of a series of model specifications, i.e. models with alternative costs drivers, suggest that one of the 17 TSOs almost always is an extreme outlier. This TSO has therefore been permanently removed from the reference set. In addition, three others have been identified using the model specific outlier detection tests explained in section 4.21, making in all four TSOs frontier outliers.

Returns to scale

5.11 For all possible model specifications, we have also tested which of the returns to scale assumptions in the DEA model fit data the best: variable returns to scale (VRS), increasing returns to scale (IRS), decreasing returns to scale (DRS), or constant returns to scale (CRS). We have done so using F-tests based on a goodness-of-fit measure as explained in the Method chapter. The general finding is that the IRS assumption (see Figure 5-2 below) is the best assumption to invoke. This is supported also by parametric analyses for a logarithmic model, where the coefficients sum to less than one for the selected parameters.

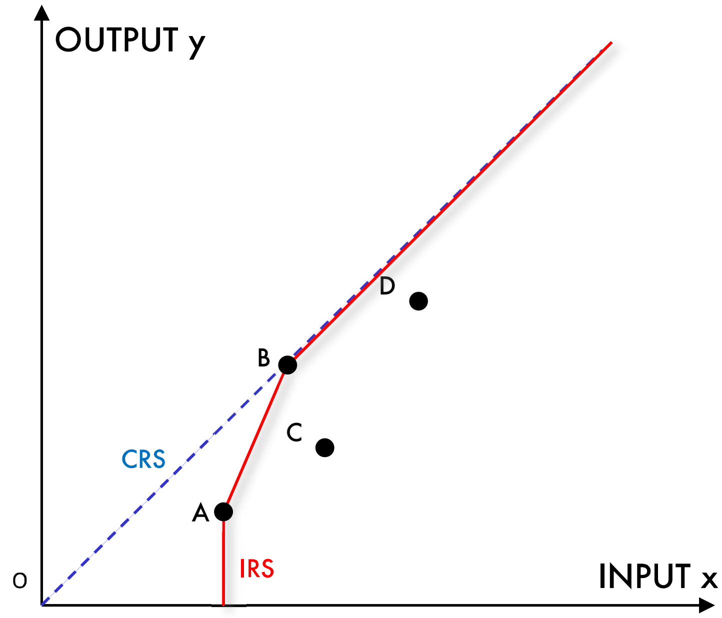

Figure 5-2 DEA frontier under increasing returns to scale (IRS).

5.12 The IRS assumption means that it can be a disadvantage to be a small TSO but not to be a large TSO. In Figure 5-2 the large TSO D is benchmarked against the most productive (CRS-efficient) TSO B, the somewhat smaller TSO C is gauged against the standard set by TSO B and A, whereas TSO A (smaller than B) forms a frontier unit for its scale class. This is also conceptually appealing. A TSO can be small due to the size of the country or by the service area it has to serve and there may be an element of fixed costs involved in the operation of any TSO. On the other hand, if a TSO is suffering from extra cost of being large, it is likely that a reorganization of the TSO to imitate a combination of smaller TSOs could improve cost efficiency.

5.3 Assumptions applied in runs

Exclusion of significant rehabilitation

5.13 Although informed in the data specification and at workshops, only very few TSOs used the reporting options for significant rehabilitations. Worse, of those reporting some TSOs reported proportions of their assets base under significant rehabilitation that do not correspond to any reasonable techno-economic policy. In order not to compromise the data quality, the PSG decided to exclude the significant rehabilitation from the benchmarking runs.

5.4 Efficiency scores

5.14 The efficiency scores are obtained using DEA on the final model described. The primary static result concerns the 2017 data.

Final model efficiencies

5.15 Summary statistics for the efficiency scores in the final TCB18 model are shown in Table 5-4 below. We see that the DEA model leads to mean efficiencies of 89.8%, i.e. the model suggests that the electricity TSOs on average can save 10.2% in benchmarked comparable Totex.

Table 5-4 Efficiency scores in final model ELEC, static 2017

	Mean	Q1	Q2 (median)	Q3
Final DEA (2017)	0.898	0.795	0.991	1.000
Peers (non-outliers)	4			
Outliers	4			

5.16 In Table 5-4 we see all the quartiles of the efficiency distribution and we note that there is a longer left tail in the sense that the median is now to the right of the mean value. This is also illustrated in the Figure 5-3 below.

5.17 The full distribution of the efficiencies is shown in Figure 5-3. We note here the relatively large number of fully efficient TSOs. This is not surprising since we are using a model with three cost drivers on a small sample and with cautious (aggressive) outlier elimination instruments. Indeed, in the base model there are four DEA outliers as stated in art 5.10.

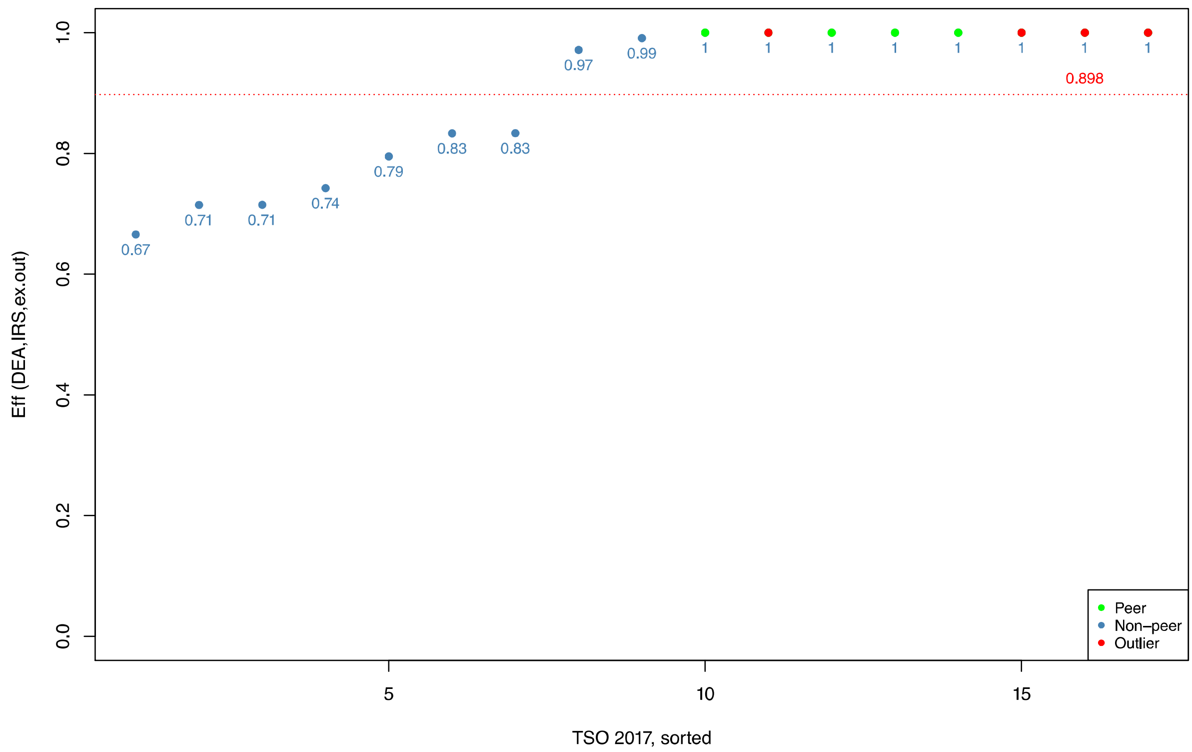

Figure 5-3 Distribution of scores 2017 in the final ELEC model.

5.5 Robustness analysis

5.18 The final model provides a cautious estimate of the cost efficiency in electricity transmission, in line with the E3GRID results in terms of level and distribution.

5.19 The revision of a preliminary model to incorporate line-weighted steel towers rather than the number of towers made the final model more comprehensive and less dependent on technology choices.

5.20 Overall, the model constitutes an improvement in the consideration of economic, environmental and infrastructure factors. Although a selection has been made among the derived environmental factors, the correlations among them render the specification robust.

Sensitivity for model parameters

5.21 The results have been tested for changes with respect to the following model parameters:

1) Interest rate
2) Normgrid weight – calibration between Opex and Capex
3) Normgrid weight for lines vs other assets
4) Salary corrections for capitalized labor in investments

5.22 All analyses are relative to the impact of a parameter change, say q on the DEA score for the base case used in the final run, q_0. For each TSO k, the impact of q is measured as :

$$E(k|\,q) \;/\; E(k|\,q_0)$$

5.23 The illustrations below concern the mean effects on the 2017 dataset, i.e. the final scores. A negative slope for the function above would imply that increasing the parameter q would lead to a decrease in mean score, the vertical axis gives an indication of the percentage change in score expected.

Sensitivity to interest rate

5.24 The results for the sensitivity to interest rate changes show a relatively flat and predictable shape. Lowering the interest rate to 1.8% (-40% of the 3% base rate) would on average increase the DEA score by 1.5% (proportionally, the maximum change is +11% units), likewise an increase to 4.5% (+50% on base rate) would on average decrease the DEA scores by 4.5% (maximum unit change: -12%). The outcomes are illustrated in Figure 5-4 below. The vertical axis denotes the change in average DEA scores relative to the average DEA scores calculated with interest rate 3%.

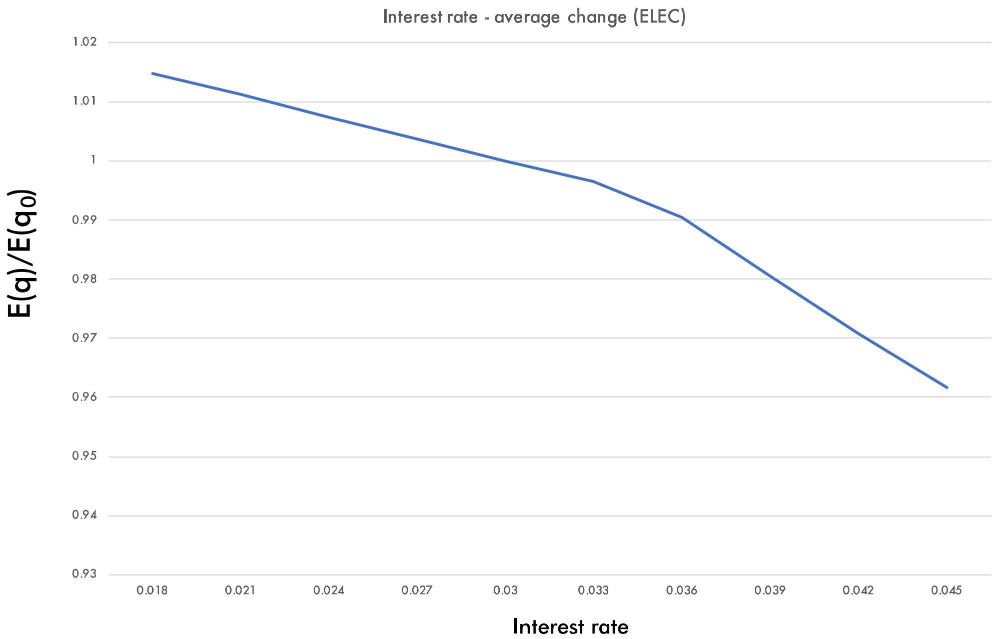

Figure 5-4 Sensivity to changes in real interest rate (proportional change in DEA score).

Sensitivity to NormGrid weights

5.25 Each TSO has thousands of assets of different types and dimension, each assigned a specific value in the Normgrid system. Given the large number of assets and their dispersion, the impact of a change to an individual weight is of course minimal. But even systematic changes to the balance between Opex and Capex weights and to specific asset groups (here: overhead lines) result in very small changes to the DEA scores, as seen in Figure 5-5 and Figure 5-6 below. The explanation for this stability is that the types of assets are relatively equally shared among the TSOs and the changes in absolute numbers hardly affect the relative ratios among the TSOs. The vertical axis denotes the change in average DEA scores relative to the average DEA scores calculated with the base values used in the NormGrid system (=1), multiplied with a factor ranging from 0.2 to 2.

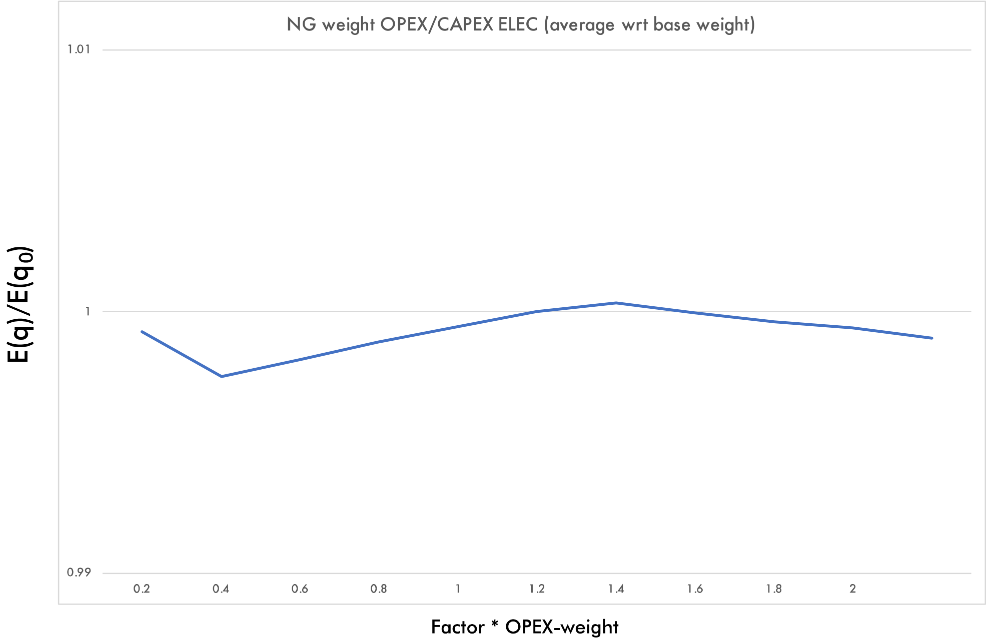

Figure 5-5 Sensitivity analysis wrt to NormGrid weights calibration Opex-Capex (change in DEA score).

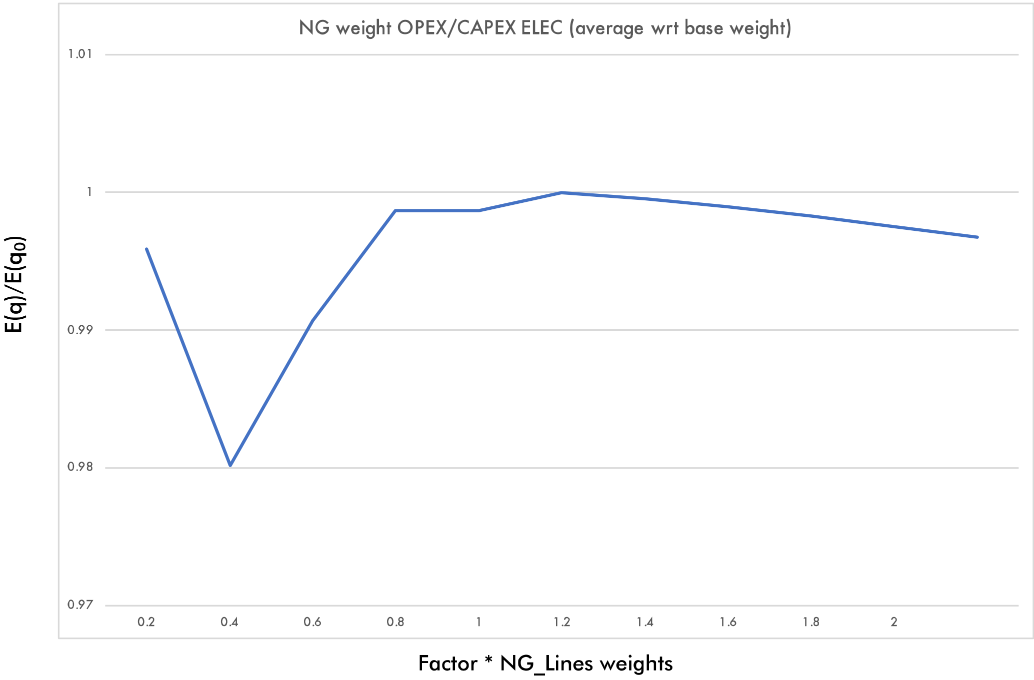

Figure 5-6 Sensitivity analysis wrt to NormGrid weights for overhead lines (factor of change) vs change in DEA score.

Sensitivity to salary corrections for investments

5.26 In E2GAS (the CEER gas TSO benchmarking 2015/2016), a share of the investment stream was considered as local labor cost and subject to the same salary adjustment as in OPEX. In TCB18 this is not the case as the identification of the constructors in past investments is uncertain and the economic interpretation (closed markets) is in conflict with promoted best practice in other infrastructure areas. The sensitivity of the results with respect to this choice is illustrated in Figure 5-7 below. The average change is minimal, less than 1% for a 25% labor share, but the individual impact of course depends on the weight of investments in Totex and the salary correction factor compared. The maximum range of impact here in the interval (-9% to +3%) in percentage-units for the score confirms that even on an individual basis, the results are not primarily driven by country-specific labor cost differences.

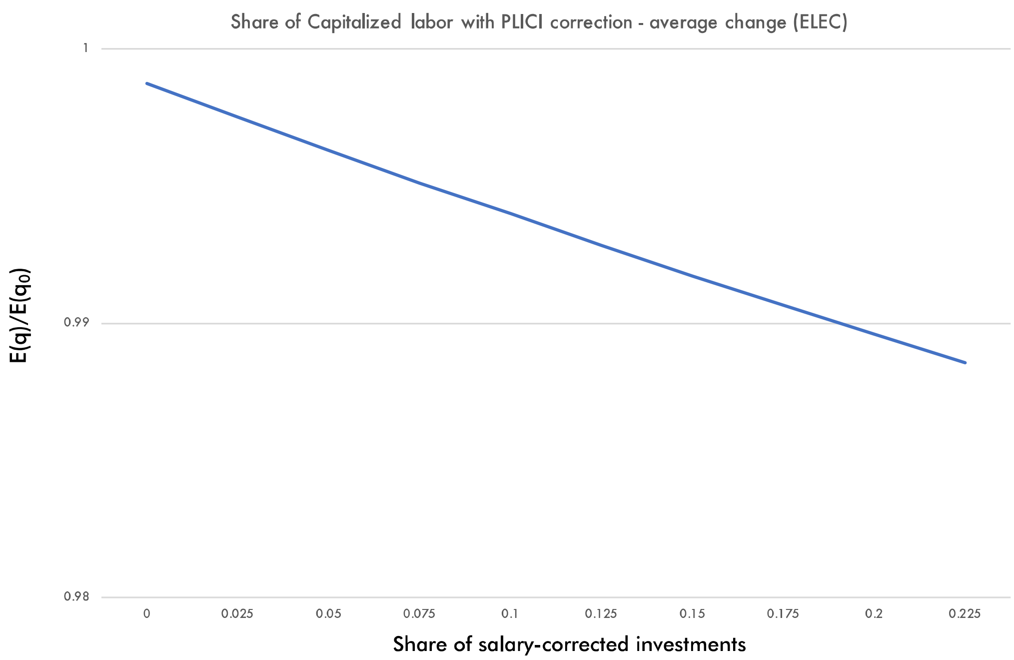

Figure 5-7 Sensitivity analysis for salary correction of capitalized labor in investments, DEA score.

5.27 The sensitivity analysis confirms that the results are robust to changes in the model parameters (interest rate, norm grid parameters) or model assumptions (capitalized labor in investments).

6. Quality provision

In this chapter, the results from a survey on indicators and data for service quality in transmission.

6.1 Survey

6.01 So far measures of output quality have not been widely used in TSO cost efficiency studies. Wherever measures of output quality have been considered and/or used, studies focused on measures for energy losses or reliability. Notably E3grid was no exception to that, although the energy not supplied asked for did not correlate very well to cost. Still, CEER remains open to add the aspect of quality to (future) benchmarks. For that, however, it is required to define the concept of quality, to find ways to measure it, and to be able to relate such measure(s) to benchmarked cost.

6.02 In order to get closer to answers, in October 2017 CEER initiated a survey among most TSOs participating in TCB18. The survey asked TSOs to suggest quality parameters that are of universal use, well defined, collectable, and verifiable with independent sources, and be as specific as possible regarding definition, interpretation, sourcing, availability, and verifiability.

6.03 CEER received responses to the survey from just two TSOs. To summarize, the first TSO (electricity) deems quality parameters in general as too susceptible to exogenous factors in order to include them in a European efficiency comparison. Their experience, as they say, shows that the link between costs or the individual effort to maintain a high asset quality and most quantifiable quality parameters like security of supply is rather weak or arbitrary. Therefore analyses of such relationships might be misleading. The second TSO (also electricity), however, pleas for taking quality into account.

6.04 To summarize, the response was too low in numbers and the outcome too diverse and not concrete enough to be conclusive. Nevertheless, at the second TCB18 workshop of April 2018 the subject was found to be important enough to reinvestigate and it was agreed to revisit the survey, this time with a questionnaire that gives stronger guidance to what CEER is looking for. The survey was launched in October 2018 with a (extended) deadline of January 2019. The survey aimed at further exploring the business know-how at TSOs to investigate if quality of service provision could be defined meaningfully in terms of cost and cost efficiency. To that extent the survey focused on searching for concrete quality aspects and ways to measure these (parameters). CEER announced beforehand that the results of the survey were not meant to be used in the model of the current TCB18 benchmark. For the second survey CEER developed an Excel template to be filled in by TSOs and gave the following instructions in a separate guiding document.

6.05 First of all, CEER remarked in the guide that quality is not about *what* a TSO provides, but *how well* it is done. Therefore, CEER expects that a suggested quality aspect is of universal relevance. That is, if a quality aspect reflects the quality of a service that is not provided by all TSOs, the quality aspect may signal a benchmark scoping issue or something else rather than a quality issue.

6.06 Secondly, the quality aspects CEER is looking for:

1) must be interpretable, i.e. a quality aspect that has not at least an intuitive relation to cost will be difficult to use for the purpose of benchmarking. So, interpretability is more or less about the story behind the quality aspect in terms of cost and cost efficiency.
2) must be measurable as a parameter. For example, if the quality aspects is reliability, a parameter may be the number of service disruptions. It is important to define such parameters well, i.e. concrete, precise, and unambiguously.
3) must have a relation to cost. Apart from a more global interpretability of the quality aspect, it helps the analysis of the survey to understand the TSO's opinion on how specific cost parameters correlate to cost and asset components. The survey asked TSO's to link suggested quality parameters to cost items in the financial reporting sheet of the TCB18 data collection.
4) must be collectable. To use a quality parameter to interpret a benchmark result or to shape the benchmark model, the value of the parameter must be based on objective data that are collectable and verifiable.

6.07 The response to the second survey was again low in numbers, diverse, and in most cases not very concrete. Two neighboring electricity TSOs submitted a response together. They mention security of supply (with measures like SAIDI or ASIDI) and remark that CEER already collects information about these parameters and should therefore have no problems in integrating this in TCB18. The TSOs further mention provision of cross border capacity, to be measured by a combination of interconnectedness and availability of cross border interconnections to the market. Also, the TSOs suggest that the level of integration of renewable energy is a quality aspect, without suggesting a clear metric for it. It continues by suggesting that the level of personal accidents in construction works is also a sign of quality. It can be measured by the loss time injury frequency. Finally, the TSOs mention the environmental impact of a TSO as a quality aspect. For that sustainability reports could be used to measure it. Finally, a third TSO warns that relation to cost of quality aspects is often difficult to measure as many complexity factors play a role as well.

6.2 Analysis

6.08 It seems clear that the reliability of transportation of energy (security of supply; measured by interruptions, energy not supplied, etc.), or actually the absence of it, appeals to what the users of the grid eminently experience as quality delivered by TSOs. The aspect has universal relevance. Given a metric for reliability that is consistently defined for all TSOs, sampled objectively, and for which the result of that is publicly available, its relation with cost could be tested for in a cost driver analysis. Practice, however, is unruly. Studies by CEER show that in many countries there are systems in place measuring reliability, but there is a lack of commonly defined metrics and measurements at TSO level, which limits the use of these in a cost efficiency benchmark substantially. So, unlike two TSOs suggested in the second survey mentioned in the above, it is not at all straightforward to apply the CEER studies in TCB18 or later benchmarks.

6.09 Still, CEER remains open to practical suggestions to solve these obstacles. It must be said, however, that the proper inclusion of a metric for reliability in a benchmark like TCB18 will probably require a substantial effort to come to a commonly defined and well measured metric on a pan-European scale and also some years after that to develop a reliable time series of systematically sampled data. The alternative would be to ask TSOs for their own recordings of reliability, though we should keep in mind that this was tried in E3grid (energy not supplied) and that several TSOs had difficulties to submit reliable data for it. Insofar data was available, a relationship with cost could not be confirmed statistically, although it is difficult to say whether that had to do with the data quality or with a true lack of relationship. In that respect, we also took notice of a TSO mentioning that *"… the link between costs or the individual effort to maintain a high asset quality and most quantifiable quality parameters like security of supply is rather weak or arbitrary. Therefore analyses of such relationships might be misleading."*

6.10 Also, like with modelling environmental conditions in TCB18, CEER desires to base the result of TCB18 and future benchmarks on as objective data as possible. In this case that means not asking TSOs for their data on reliability, but collecting it from exogenous, independent sources. Hence, CEER believes the alternative approach of asking TSOs for their own data is not attractive, not in TCB18 and not in the future.

6.11 Regarding other suggestions made, they seem less suitable to see these as quality aspects. Some suggestions done are more about *what* a TSO does, not *how well* it is done. Other suggestions lack sufficient universal relevance, lack an obvious and practical metric, or are seen as much less relevant to analyse and implement than something like reliability.

6.3 Conclusions

6.12 To conclude, CEER remains open to defining and implementing quality aspects, but sees on the basis of the responses to the surveys and available material currently no way to do this properly. CEER calls upon European independent institutions to set a common standard for measuring reliability and publish the results regularly and openly. As soon as that has been done, CEER will be able to revisit the theme of explicitly addressing quality in cost efficiency benchmarking.

7. Summary and discussion

7.1 Main findings

7.01 The TCB18 project has established a comprehensive platform for cost efficiency assessments in electricity transmission through a set of detailed data specifications for assets, activities, costs and environmental conditions. The specifications have been reviewed in several rounds by NRAs, TSOs and external experts to be as relevant and clear as possible. A new efficient organization of the data collection and validation has been implemented, managed by the PSG, more precise by the NRAs for cost and asset data and managed by consultants for the collection of environmental parameters mapped to the service areas of the operators. This process is forming a stable and powerful basis for periodic performance assessments and the systematic collection of data to gauge the development of the sector.

7.02 The collected data have been processed in order to derive a benchmarking model capturing the three main service dimensions (grid provision, capacity provision and customer service) considering heterogenous economic and environmental conditions and technical specifications. Using the normalized grid metric, the multiple assets of the power system have been included to form a Totex-relevant proxy for grid size, more predictive to cost than using conventional measures such as line length or energy transported. Using statistical methods to derive the most informative models, a final model with three outputs and one input, Totex, has been developed.

7.03 The cost efficiency results from the model present a mean cost efficiency for 2017 corresponding to 90% of relevant Totex. This result indicates an efficiency improvement potential that is on average about 10%. The potential appears to be a very conservative estimate of the true prospect for performance improvements in the sector, here excluding all effects of capacity utilization and energy consumption that could be added to the picture. However, the results do indicate examples of best practice to be analyzed and emulated, as well as providing information to regulators and operators about the sources of inefficient investments and operations.

7.2 Plausibility of the results

7.04 One way of looking at the results is to ask oneself if it is reasonable to believe that individual scores can come out as low as 80%, 70%, 60%, or even lower. The answer to that question is in our view YES for two important reasons. First of all, the TCB18 project itself has been performed with great care, i.e. extensively validating data, often making cautious assumptions when modelling, and verifying the results to the extent that the PSG cannot think of any reason why these could not be trusted. Often these steps were inspired by comments from TSOs, leading to the formulation and testing of additional hypothesis to rule out errors as much as possible.

7.05 Another interesting point of view is founded on the outcome of other benchmarking studies focusing on infrastructure sectors. Notably in gas and electricity many studies exist with similar outcomes as for TCB18. But also looking at a typical project in rail infrastructure efficiency made for the European Commission (Steer Davis Gleaves, 2015), one can see a considerable spread in raw cost efficiency, not explained by size, and in the DEA scores (that are particularly "soft" using a 2-input, 3-output model). Indeed, there are large differences in the way heavy infrastructure is planned, procured and operated - even if the operators use tendering and are incentivized (nationally).

7.06 We can even take this argument further, by looking at a non-infrastructure sector, like banking. To measure their efficiency banks commonly use the cost-to-income ratio. Seen as a unit cost efficiency measure, which is reasonable given that often banks focus on cost reductions to improve their ratio, we see banks worldwide having very low efficiencies. Even on a European Union scale, we see numbers as low as 50% in 2014, see https://m.theglobaleconomy.com/rankings/bank_cost_to_income .

7.07 Having observed this, it is important to realize that individually there can be many good reasons for very low or very high efficiency scores and that it is not the purpose of TCB18 to judge about that. With TCB18 a best practice frontier has been developed in a pan-European context, based on verifiable observations while maintaining a neutral position towards national circumstances.

7.3 Comparison with E3GRID

7.08 The earlier E3GRID model has a similar base structure using a grid asset proxy (NormGrid) and a routing complexity output linked to the line length and the angular towers (cf. art 5.06). However, the TCB18 approach is more advanced than E3GRID in three aspects:

1) GIS-level integration of exogenous environmental factors. Whereas E3GRID operated with a greenfield-approach for grid construction costs, TCB18 incorporates the landuse factors for the service area directly at a very high level of detail, without problems related to self-reporting and data validation access.
2) No population density proxy. In E3GRID, in lack of good data for landuse a simple area indicator for dense urban area was used as a separate output variable. The inclusion of non-operation related outputs forced the application of weight restrictions in the model, which increased calculation and interpretation complexity. In TCB18, the landuse factors are exhaustive and multiplicative, rendering such application unnecessary.
3) Capacity output parameter. In E3GRID that capacity dimension was limited to the consideration in the NormGrid. However, this is impacted by the age of assets (older transformers have little impact) and the focus is on the capex-impact (cost function for transformers, relative weights between transformers and other assets). In TCB18, the capacity offered to the system, irrespective of the age and configuration of the assets, is included as a separate output.

7.09 The size of the models and the number of participating TSOs in TCB18 and E3GRID also explain part of the difference in the results (E3GRID 2012: 21 TSOs, mean efficiency 86% and 8 peers). However, both the distribution and level of the results are very similar to those of E3GRID.

7.4 Limitations

7.10 Although state-of-the-art statistical techniques have been applied to determine the optimal combination of environmental factors for the final model, some conditions might apply to an individual or small group of operators passing undetected in the model specification. In the case the combined effects are significant, the systematic two-stage outlier detection in DEA would identify and remove the data. However, there might be cases of impact without being sufficient for outlier classification that merit the attention of the NRA in interpreting the results from the study and their potential use in informing regulatory decisions.

7.5 Future plans for benchmarking

7.11 Regulatory benchmarking has reached a certain maturity through this process and model development, signaling both procedural and numerical robustness. Drawing on the work, the definitions and data standards as well as the model, CEER can readily plan for a repeated regular benchmarking at a considerably lower cost in time and resources, to the benefit of all involved. Although the current model brings improvements in particular in environmental factors, the inflation and salary corrections and the NormGrid definitions, the relative symmetry with the earlier model from E3GRID can be seen as a confirmation of the type of parameters and approaches chosen, leading to stable and predictable results. In this manner, the future work can be directed towards further refinement of the activity scope and the interpretation of the results, rather than on the model development.

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Appendix

A. Electricity asset reporting guide, 2018-03-08

B. Financial reporting guide, 2018-03-08

C. Special conditions reporting guide, 2018-09-13

D. Method to treat upgrading, refurbishing and rehabilitation of assets in TCB18

E. Modelling opening balances and missing initial investments, 2018-01-11

F. Norm Grid Development Technical Report, 2019-02-27 V1.3

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Acronyms

Table 0.1: Acronyms in the report.

Acronym	Definition
AE	Allocatively Efficient
CAPEX	CAPital EXpenditure
CRS	Constant Returns to Scale
DEA	Data Envelopment Analysis
fte	full time equivalents
I	Indirect support services (activity)
IRS	Increasing Returns to Scale
L	LNG terminal services (activity)
M	Maintenance services (activity)
NDRS	Non-Decreasing Returns to Scale
O	Other (out-of-scope) services (activity)
OPEX	OPerating EXpenditure
P	Planning services (activity)
S	System operations (activity)
SC	Staff intensity (scaled)
SE	Scale Efficiency
SF	Energy storage services (activity)
SI	Staff intensity per NormGrid unit
T	Transport services (activity)
TCB18	(CEER) Transmission Cost Benchmarking project 2018
TO	Offshore transport services (activity)
TOTEX	TOTal EXpenditure
TSO	Transmission System Operator
UC	Unit cost (cost per NormGrid unit)
VRS	Variable Returns to Scale
X	Market facilitation services (activity)

Chapter 1

Results

The following material is a summary of results, descriptive data and sensitivity analyses for Statnett with code number 190 in the TCB18 benchmarking based on data processed 15.04.2019. This release is exclusively made to the authorized NRA and the information contained in this release is not reproduced as such in any other project report for TCB18. All underlying information in this release is subject to the confidentiality agreement of TCB18. This report with associated data files is part of the final deliverables for the TCB18 project. The contents of this report are strictly confidential.

The benchmarking model of the TCB18 project uses a total expenditure measure as input and the costs drivers listed in Table 2.6 below. In addition, it is a Data Envelopment Analysis (DEA) model which means that it determines the best practice among the TSOs and uses this as the standard for evaluating each of the firms in the sample.

DEA constructs a best practice frontier by departing from the actual observations and by imposing a minimal set of additional assumptions.

One assumption is that of *free disposability* which means that one can always provide the same services and use more costs and that one can always provide less services at given cost levels. In the base model, this is an entirely safe assumption, but it does allow us to identify more comparators for any given TSO.

Another assumption is that of *convexity*. It basically means that one can make weighted averages of the performance profiles of two or more TSOs. This is a more technical assumption widely used in economics.

The third assumption is that of *non-decreasing returns to scale* or as it is sometimes called, *(weakly) increasing returns to scale*. It means that if we increase the costs of any given TSO with some percent, we should also be able to increase the service output, the costs drivers, with at least the same percent. We can also formulate this as an assumption that it can be a disadvantage to be small, but not to be large. It is important that this assumption is not just imposed *ex ante*. The statistical analysis of alternative returns to scale models suggests that it actually is a reasonable assumption to make in the sample of electricity transmission operators in this study.

The best practice DEA model and the theory behind it are further explained in the main report and its accompanying appendices.

Using the base model, we have estimated the efficiency level of Statnett to be

74.2 %

The interpretation is that using best practice, the benchmarking model estimates that Statnett is able to provide the same services, i.e. keep the present levels of the cost drivers, at 74.2 % of the present total expenditure level. In other words, the model suggests a saving potential of 25.8 % or in absolute terms, a savings in total comparable expenditure of

87 MEUR

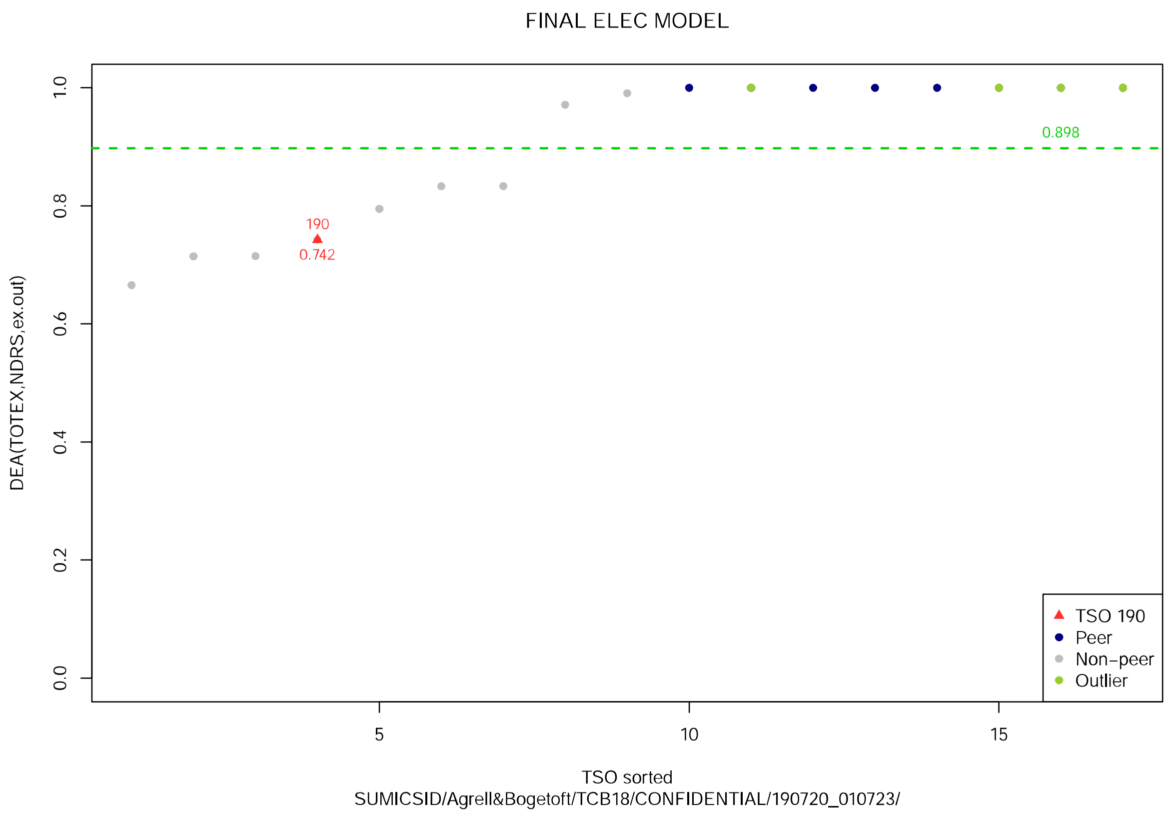

Figure 1.1: Final DEA cost efficiency results for electricity TSO in TCB18 .

The model considers both investment efficiency and operating efficiency under a given set of environmental conditions. The material in this report may provide elements to explore other differences than those explicitly included in the model, to understand the scores and the operating practice of the electricity transmission operators in Europe in 2017.

To evaluate the estimated efficiency of Statnett, it is always relevant to compare to the efficiencies of the other TSOs in the TCB18 project, see Figure 1.1. Structural comparability is assured by stringent activity decomposition, standardization of cost and asset reporting, harmonized capital costs and depreciations, elimination of country-specific costs related to taxes, land, buildings, and out-of-scope activities, correction for salary cost differences and national inflation as well as currency differences.

Table 1.1: Efficiency scores year 2017

	Mean eff	#outliers
All TSO	0.898	4
Statnett	0.742	0

Chapter 2

Data

The data collected in the TCB18 project is extremely rich and cannot be fully represented in a short summary. Hence, the reporting for each individual operator includes the following documents in addition to this report:

1. Asset sheet with Normgrid values.
2. Cost data sheet (Capex and Opex).

Below in Table 2.1, we provide an overview of the model data used and some descriptive statistics for the units.

Table 2.1: Detailed asset summary (usage share included) 2017

	Code	Units 2017	Units <1973	NGCapex	NGOpex	NGTotex
Overhead lines	10	278	128	116,983,657	18,716,966	135,700,623
Cables	20	62	5	14,612,434	30,923	14,643,358
Circuit ends	30	1,405	350	37,862,789	21,566,609	59,429,399
Transformers	40	253	49	13,492,936	1,739,596	15,232,532
Compensating devices	50	144	1	6,294,957	703,380	6,998,338
Series compensations	60	14	0	149,571	17,336	166,906
Control centers	70	3	0	220,341	229,469	449,810
Other installations	90	5	0	0	0	0
TOTAL				189,616,687	43,004,279	232,620,966

Table 2.2: Detailed asset summary (usage share included) 2016

	Code	Units 2016	Units <1973	NGCapex	NGOpex	NGTotex
Overhead lines	10	265	128	105,782,097	17,497,397	123,279,494
Cables	20	59	5	13,636,081	30,510	13,666,591
Circuit ends	30	1,361	350	36,312,954	20,869,184	57,182,138
Transformers	40	252	49	13,429,109	1,732,519	15,161,629
Compensating devices	50	144	1	6,294,957	703,380	6,998,338
Series compensations	60	14	0	149,571	17,336	166,906
Control centers	70	3	0	220,341	229,469	449,810
Other installations	90	5	0	0	0	0
TOTAL				175,825,111	41,079,795	216,904,906

Table 2.3: Detailed asset summary (usage share included) 2015

	Code	Units 2015	Units <1973	NGCapex	NGOpex	NGTotex
Overhead lines	10	258	128	99,847,387	16,879,682	116,727,069
Cables	20	55	5	10,089,255	28,089	10,117,344
Circuit ends	30	1,313	350	34,713,430	20,149,398	54,862,827
Transformers	40	248	49	12,941,738	1,697,437	14,639,175
Compensating devices	50	143	1	6,235,393	703,157	6,938,551
Series compensations	60	14	0	149,571	17,336	166,906
Control centers	70	2	0	146,894	152,979	299,873
Other installations	90	5	0	0	0	0
TOTAL				164,123,668	39,628,078	203,751,746

Table 2.4: Detailed asset summary (usage share included) 2014

	Code	Units 2014	Units <1973	NGCapex	NGOpex	NGTotex
Overhead lines	10	255	128	97,601,446	16,653,118	114,254,564
Cables	20	52	5	9,708,034	27,788	9,735,822
Circuit ends	30	1,285	350	33,731,667	19,707,604	53,439,272
Transformers	40	241	49	12,556,011	1,653,146	14,209,157
Compensating devices	50	142	1	6,225,939	702,935	6,928,873
Series compensations	60	14	0	149,571	17,336	166,906
Control centers	70	2	0	146,894	152,979	299,873
Other installations	90	5	0	0	0	0
TOTAL				160,119,563	38,914,906	199,034,468

Table 2.5: Detailed asset summary (usage share included) 2013

	Code	Units 2013	Units <1973	NGCapex	NGOpex	NGTotex
Overhead lines	10	247	128	94,172,546	16,341,935	110,514,480
Cables	20	51	5	9,645,618	26,381	9,671,999
Circuit ends	30	1,229	350	31,503,693	18,705,016	50,208,710
Transformers	40	223	49	11,065,337	1,520,291	12,585,628
Compensating devices	50	133	1	5,440,989	596,697	6,037,686
Series compensations	60	9	0	126,108	14,624	140,732
Control centers	70	2	0	146,894	152,979	299,873
Other installations	90	4	0	0	0	0
TOTAL				152,101,186	37,357,923	189,459,109

2.1 Capex-break

In the gas benchmarking, one operator was subject to the capex-break method described in the main report. However, the application was not made to prevent an infeasible target, but to avoid an absurd datapoint. In the particular case, using the official inflation metric for the entire investment stream would lead to a Capex value that exceeds the sum of all Capex in the sector, or 10,000 times higher than the actual regulatory asset base (RAB) for the operator! Obviously, the early inflation values in this country do not correspond to a realistic assessment of the network capital valuation. By using capex-break, a new value relatively close to the actual comparable value was calculated.

In the electricity benchmarking, no operator was subject to capex-break.

2.2 Capex-old

The assets prior to 1973 still operating at the reference year provide output in terms of NormGrid, but the investment stream is not reported. To compensate for this, the CapexBreak methodology above has been applied to calculate a corrective term with equal unit cost to the period 1973-2017. This means that the added Capex does not change the investment efficiency for the evaluated operator, it merely assures equal consideration of prior investments for operators with longer or shorter investment streams.

There has been no correction for pre-1973 assets for Statnett . This is due to the fact that Statnett has an opening investment later than 1973, including the pre-1973 assets.

2.3 Model input and output

The single input (Totex) and the relevant outputs for the benchmarking model for Statnett are listed in Table 2.6 below. The exact calculation of the inputs and outputs is documented in the separate confidential spreadsheets provided for each TSO on the project platform.

Table 2.6: Model data year 2017

Type	Name	Value	Mean	TSO/mean
Input	dTotex.cb.hicpog_plici	338,786,640	290,928,519	1.16
Output	yNG_yArea	279,645,992	304,572,352	0.92
Output	yTransformers_power	55,829	44,303	1.26
Output	yLines.share_steel_angle_mesum	1,403	2,096	0.67

Chapter 3

Regression analysis

The robust regression results for the final model are presented below. The dependent variable is as before *dTotex.cb.hicpog_plici*. Regression results for alternative models and variants were presented at project workshops W4 and W5.

Table 3.1:

	Dependent variable:
	refmod[[rfm]]
yNG_yArea	0.302***
	(0.047)
yTransformers_power	4,196.088***
	(208.079)
yLines.share_steel_angle_mesum	16,770.490***
	(2,986.596)
Observations	81
R^2	0.981
Adjusted R^2	0.980
Residual Std. Error	59,571,597.000 (df = 78)
Note:	*p<0.1; **p<0.05; ***p<0.01

Chapter 4

Sensitivity analysis

4.1 Scale efficiency

The productive efficiency depends on a multitude of factors, including the scale of operations. In DEA, the model can easily calculate these effects through the concept of different assumptions of returns to scale. In Figure 4.1 a reference set of four points is analyzed. Using constant returns to scale (CRS), only operator B is deemed cost efficient, located at the most productive scale (MPS). Thus $DEA_{CRS}(B) = 1$. The smaller operator A has a lower cost-efficiency than B, operating at an inefficient scale, $DEA_{CRS}(A) < 1$. However, as discussed above, a smaller scale may be imposed by a national border and/or a concession area, beyond the control of the operator. Thus, the frontier assumption of increasing returns to scale (IRS) or non-decreasing returns to scale (NDRS) illustrated by the red curve in 4.1 renders A fully efficient; $DEA_{IRS}(A) = 1$. Finally, an operator such as C that is CRS-inefficient but above optimal scale is also inefficient under IRS, but efficient under variable returns to scale (VRS), i.e. $DEA_{CRS}(C) = DEA_{IRS}(C) < 1$ and $DEA_{VRS}(C) = 1$. VRS is the weakest assumption available, it assumes both diseconomies of scale for small and large units. In network operations the diseconomies of size (e.g. congestion), are not considered relevant. However, the results allow the calculation of the economy of scale effect through the formula:

$$DEA_{SE}(k) = \frac{DEA_{CRS}(k)}{DEA_{VRS}(k)} \tag{4.1}$$

The actual scale efficiency results for the electricity transmission system operators in TCB18 are given in Table 4.1 and in Figure 4.2 below.

Table 4.1: Scale efficiency DEA(SE)

	Mean eff	#scale-efficient
All TSO	0.964	7
Statnett	0.955	0

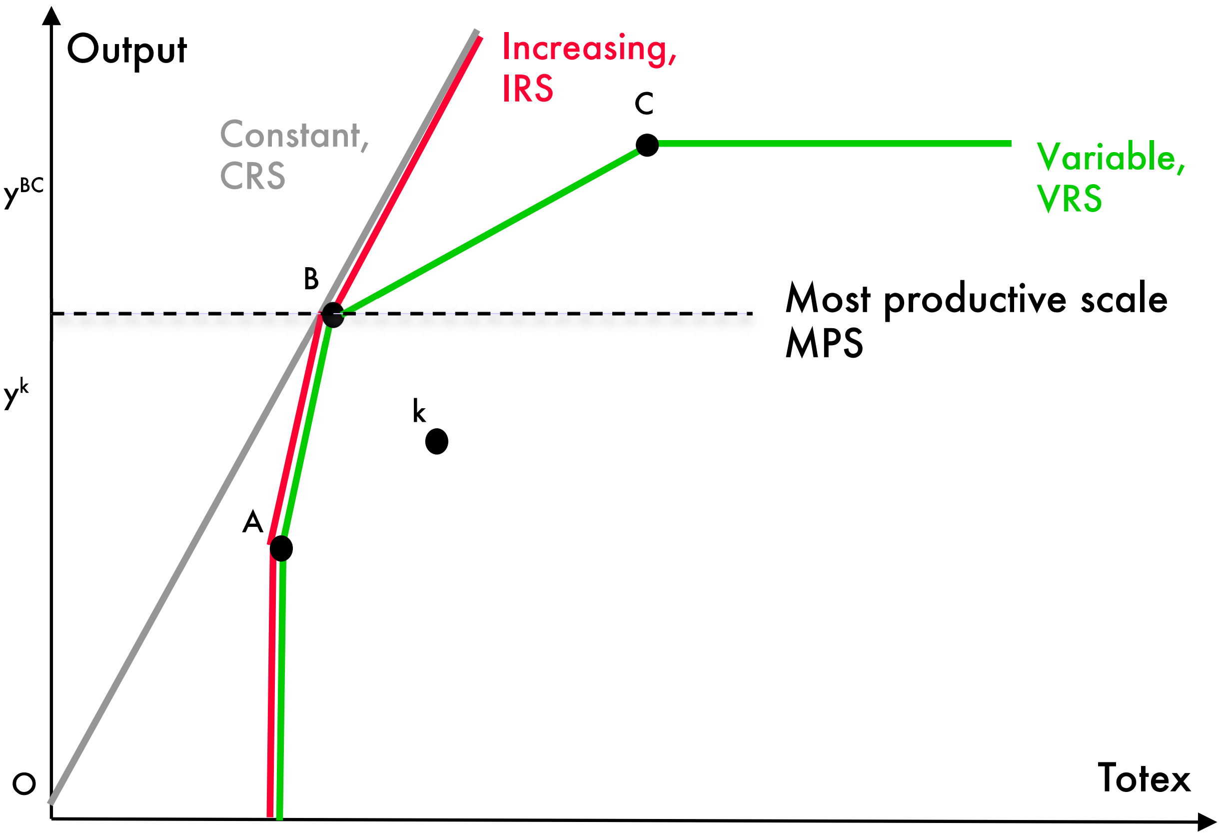

Figure 4.1: DEA frontiers CRS, IRS and VRS and scale efficiency (SE).

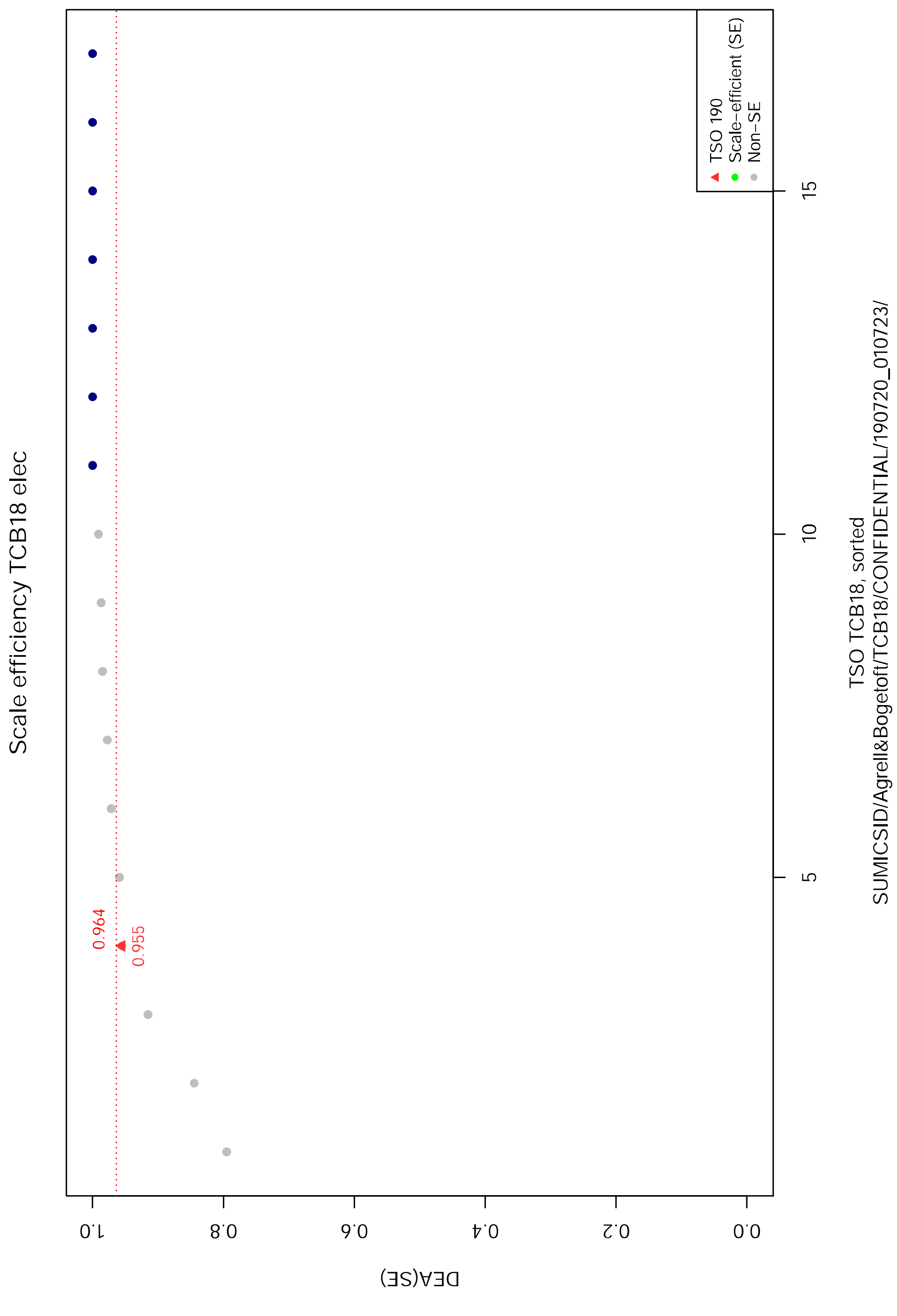

Figure 4.2: Scale efficiency, $DEA_{SE}(k)$.

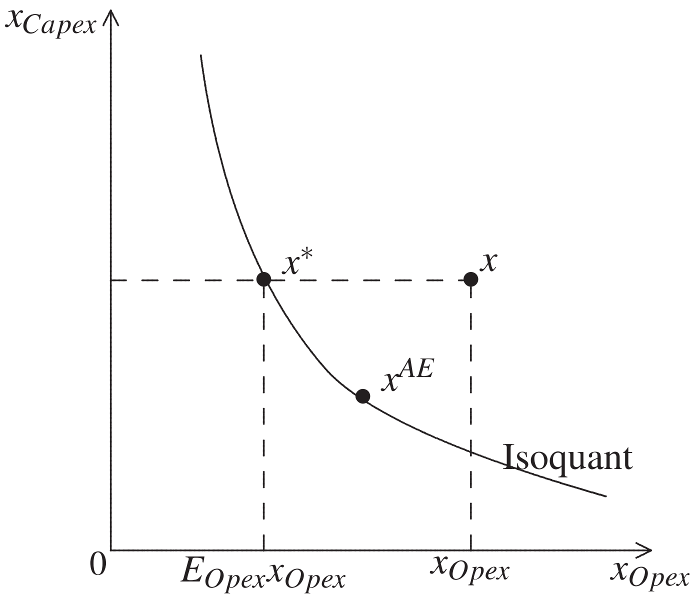

Figure 4.3: Opex efficiency E_{Opex} with fixed Capex.

4.2 Partial Opex-capex efficiency analyses

In regulatory benchmarking, it is common to focus on Totex efficiency. The question is whether TSOs can provide the same level of services with less Totex. To evaluate this, one needs a model with one input, Totex, and the usual cost drivers as outputs.

Now, Totex is the sum of Opex and Capex,

$$Totex = Opex + Capex$$

and one may therefore ask how much the TSOs could save on Opex (with fixed Capex) or on Capex (with fixed Opex). This is what we call Opex and Capex efficiency. To evaluate this, we need a model with two inputs (Opex and Capex) and the usual cost drivers.

Figure 4.3 illustrates the idea of Opex Efficiency where we project horizontally (on Opex) for a fixed level of Capex (vertical axis).

Capex efficiency is similar except that we project the observed Opex-Capex combination $x = (Opex, Capex)$ in the vertical direction for a fixed Opex level.

It follows from these definitions that all points on the input isoquant will be fully efficient from a partial Opex as well as a partial Capex perspective. This does not mean that all the points are fully Totex efficient however. In the illustration, the sum of Opex and Capex is only minimal at one point on the isoquant, namely x^{AE}.

In our analysis, we do not know the location of the isoquant. Instead we estimate the location using Data Envelopment Analysis. This means that the isoquant becomes piecewise linear like in Figure 4.4 below with corresponding values in Table 4.2.

It also means that there will typically be quite a large number of TSOs on the estimated frontier and in consequence a large number of TSOs that cannot save Opex given Capex and vice versa. However, this does not necessarily mean that they are all Totex efficient. Note in the numerical example that only TSO C is Totex efficient, as can easily be seen also from the table. Notwithstanding, TSOs A, B, C, and D are all fully Opex and Capex efficient.

To sum up, TSOs that are Opex- and Capex-efficient cannot save Opex for fixed Capex, nor Capex for fixed Opex. However, this does not imply that they cannot save on Totex. The reason is that the mix between Opex and Capex may not be optimal. A TSO like D in the numerical example can save a lot of Opex, but it requires a small increase in Capex.

Note that in Fig. 4.5-4.7 a single point in the graph may represent multiple operators with the same value, the graphs contain all participating operators.

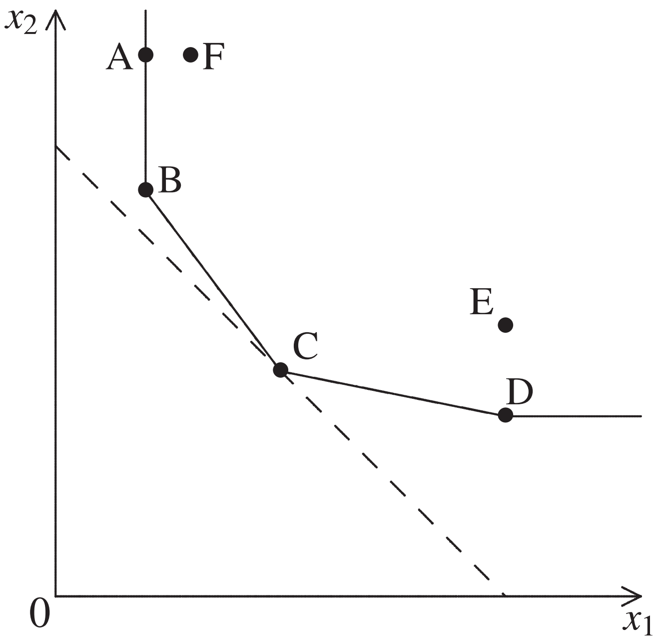

Figure 4.4: Partial Opex- and Capex-efficiency: numerical example.

Table 4.2: Partial opex-capex efficiency: numerical example.

TSO	Opex	Capex	Output	Totex
A	2	12	1	14
B	2	9	1	11
C	5	5	1	10
D	10	4	1	14
E	10	6	1	16
F	3	12	1	15

Table 4.3: Partial DEA scores year 2017

	DEA(Opex)	DEA(Capex)
All TSO	0.902	0.885
Statnett	0.585	0.417

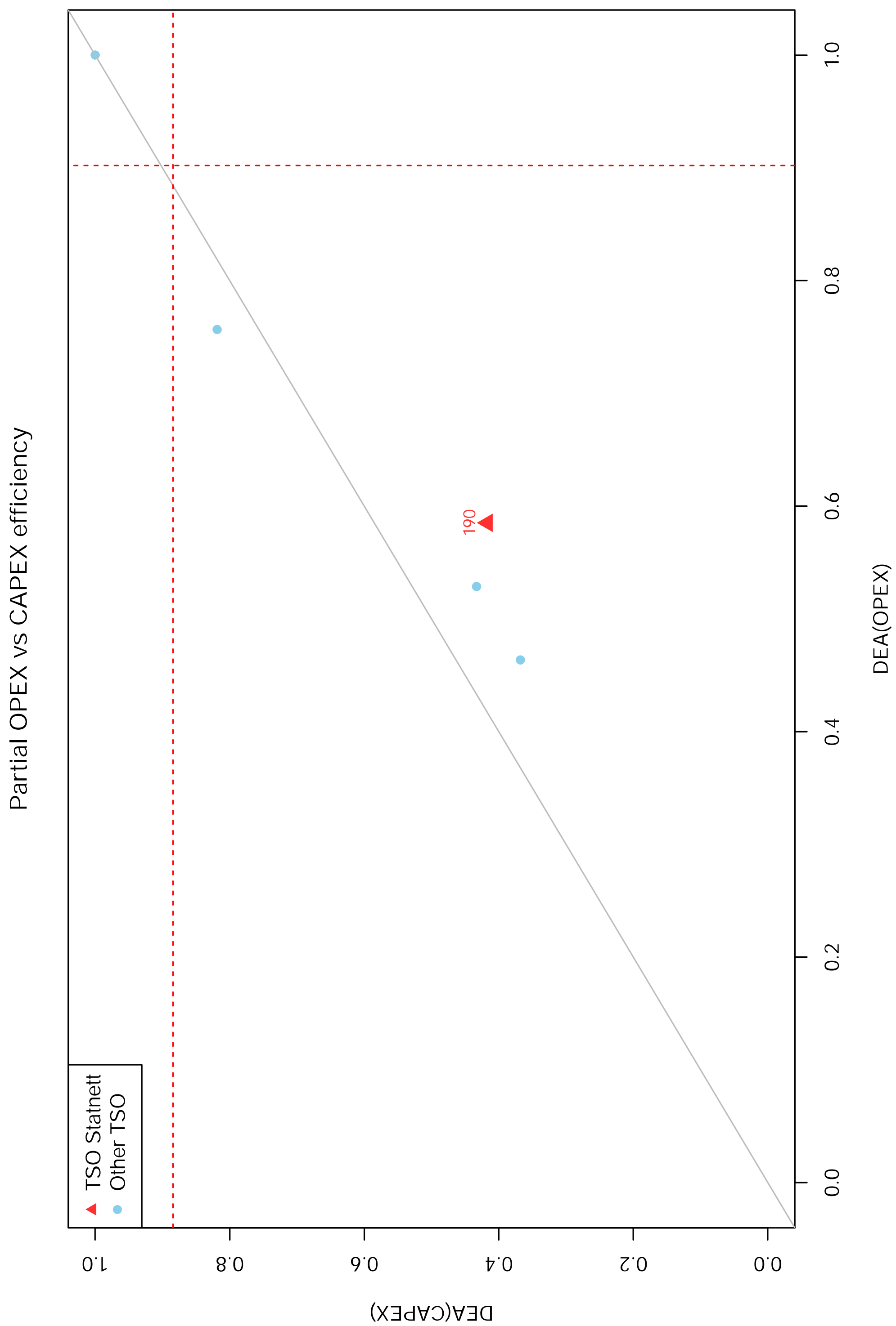

Figure 4.5: Partial OPEX and CAPEX efficiency in TCB18 (red dashed line=mean).

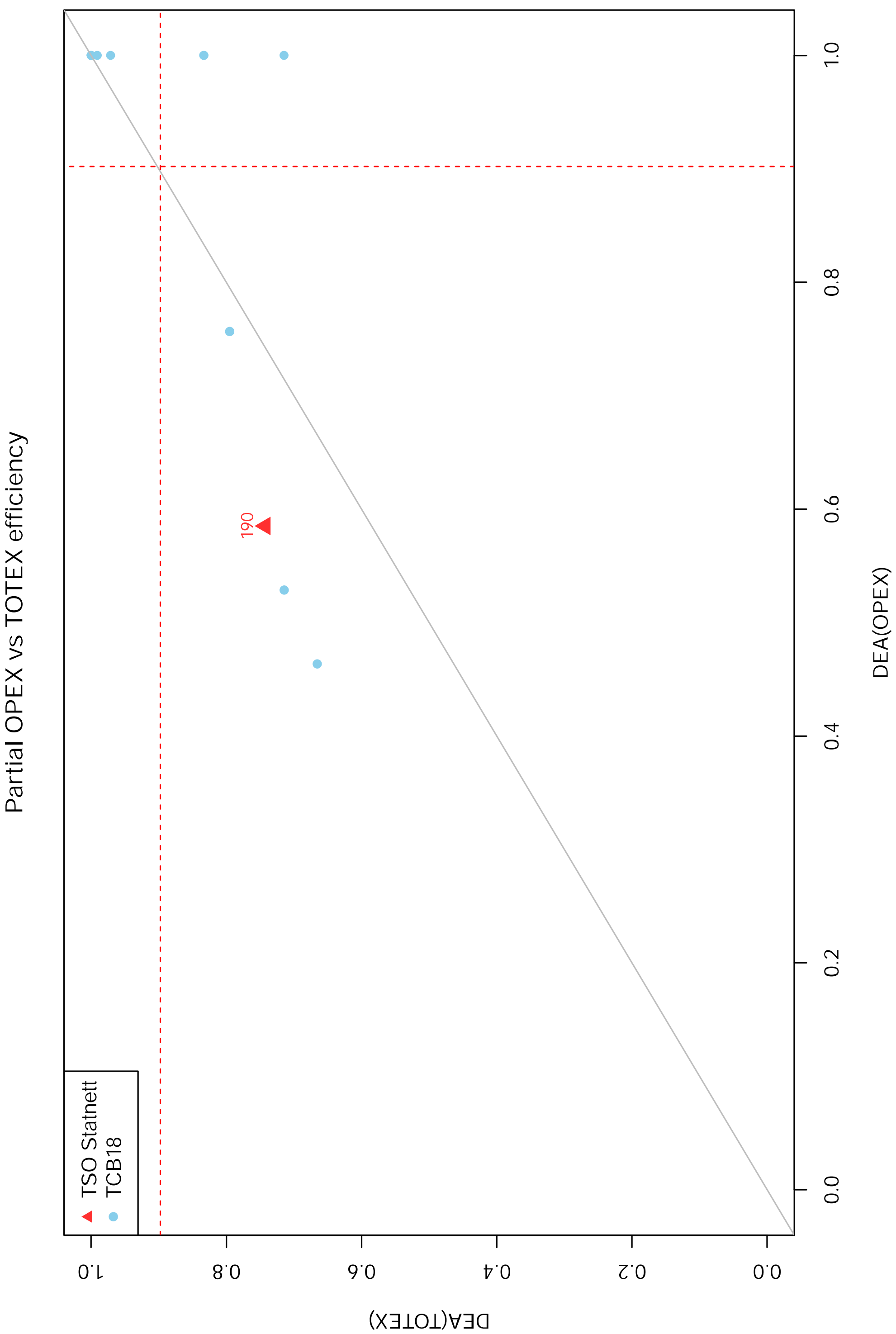

Figure 4.6: Partial OPEX vs TOTEX efficiency in TCB18 (red dashed line=mean).

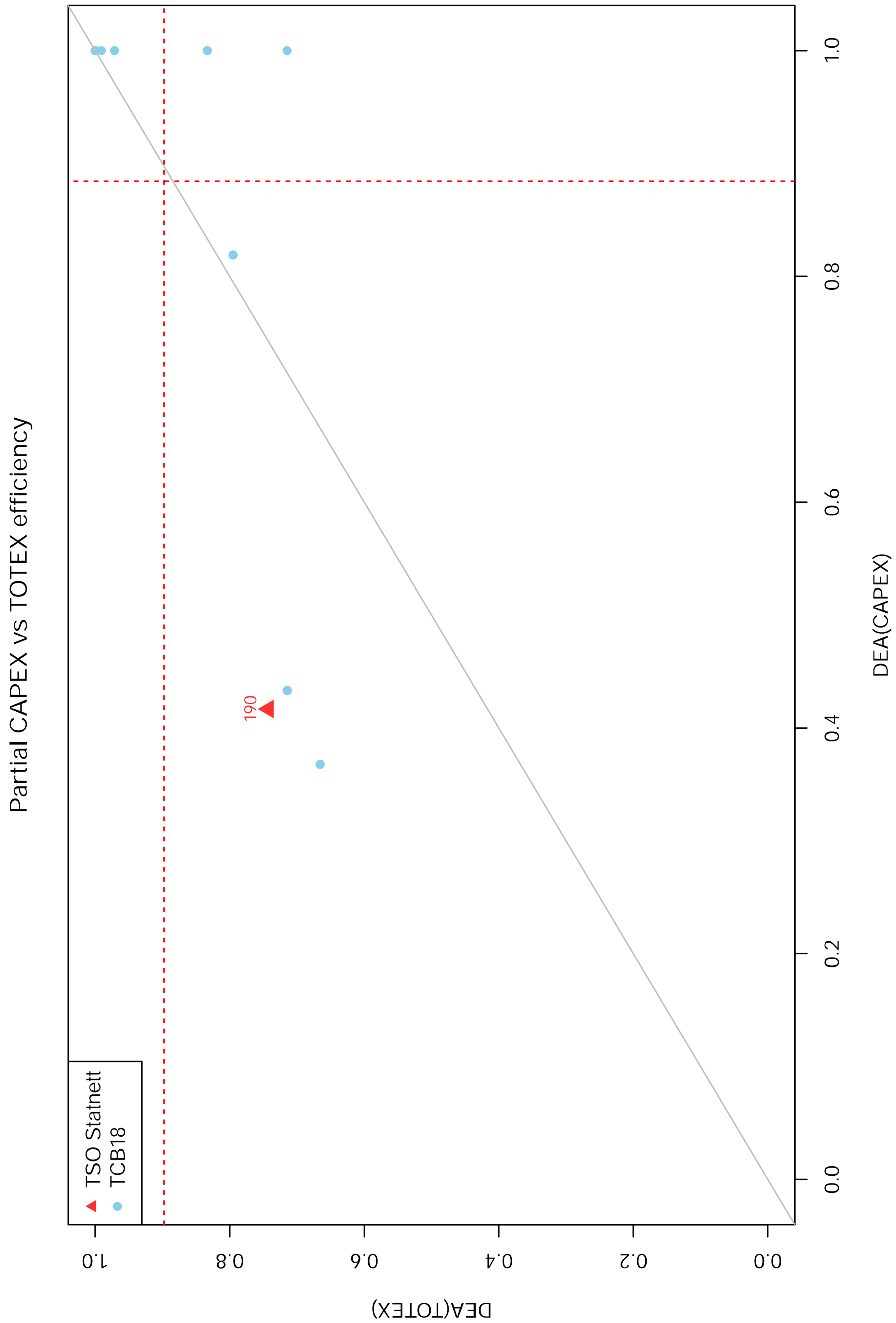

Figure 4.7: Partial CAPEX vs TOTEX efficiency in TCB18 (red dashed line=mean).

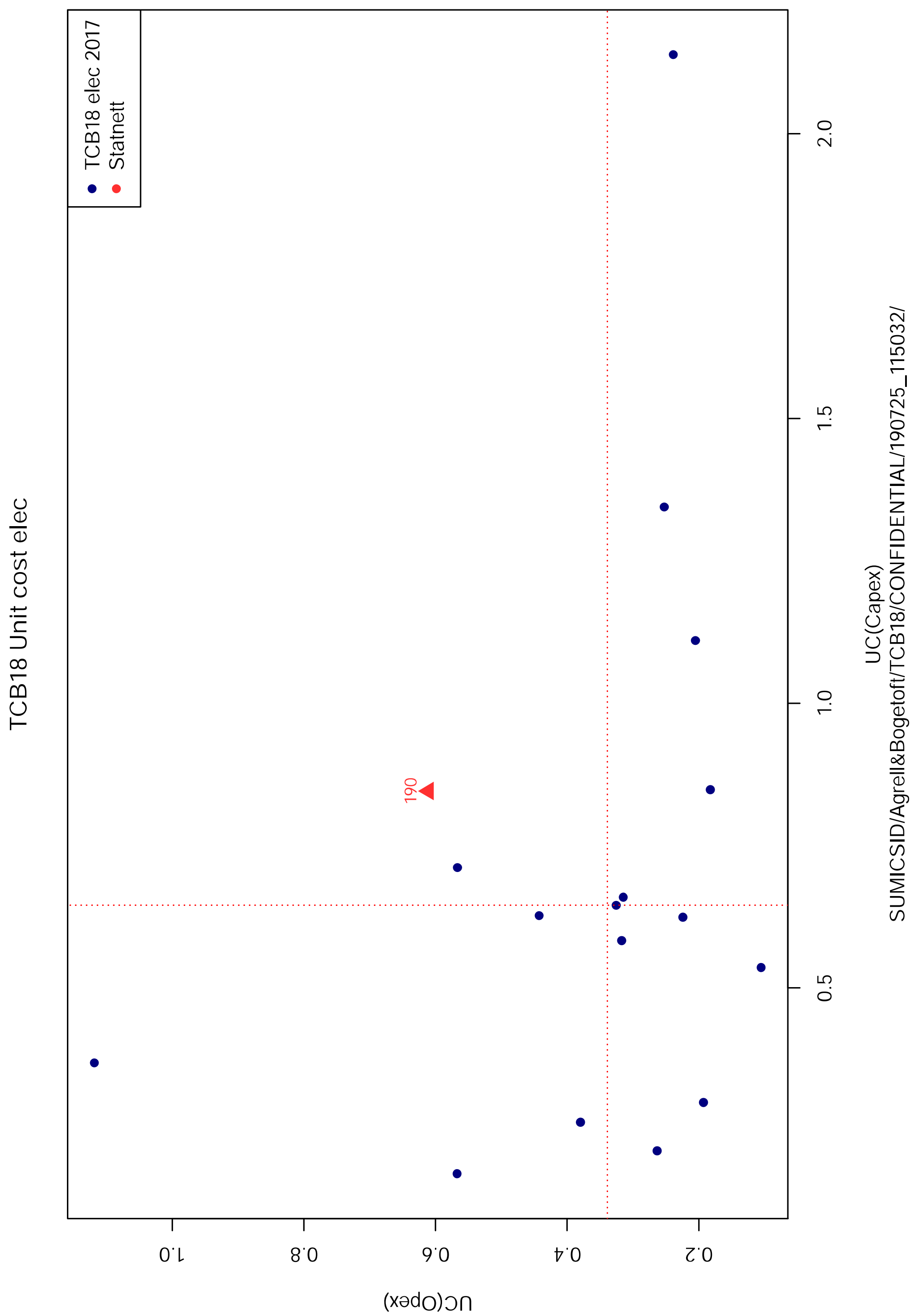

Figure 4.8: Unit cost UC(Opex) vs UC(Capex).

4.3 Sensitivity analysis

The calculated cost functions are proportional to a number of parameters, e.g. the NormGrid weights. However, since a frontier benchmarking is an investigation into relative, not absolute, changes, the scales of the inputs and outputs are not important. The relevant evaluation in this context is whether a change in a technical parameter would lead to changes in the relative ranking or level of the benchmarked units. To investigate this aspect, the following model parameters have been varied and the resulting changes in the efficiency score for Statnett are illustrated in the following graphs

Tested parameters

1. Interest rate, Fig. 4.9
2. Normgrid weights: calibration between Opex and Capex parts, Fig. 4.10
3. Normgrid weights: calibration for transport assets, Fig. 4.11
4. Normgrid weights: calibration for compressor/transformer assets, Fig. 4.12
5. Age assumptions for standardized life time, Fig. 4.13
6. Salary corrections for capitalized labor in investments, Fig. 4.14

For the analyses 1-4, a specific parameter w is varied using a factor k from 20% (-80%) to 200% (+100%) multiplied with the base value for the parameter, w_0. All other parameters remain at their base value, used for the final run. The graph then shows the efficiency score $DEA(kw_0)$ and the mean efficiency in the dataset.

Analysis 5 in Fig. 4.13 looks at the impact on the score of the assumptions regarding the standardized life time per asset. For simplicity, we have reduced the simulation to two alternative cases, Age_{low} and Age_{high}, respectively with correspondingly about 10 years shorter and longer lifetimes. The exact parameters are reproduced in Table 4.4 below.

Table 4.4: Standard age variants (years)

	Age-Low	Base case	Age-High
Overhead lines	50	60	70
Cables	40	50	60
Circuit ends	35	45	55
Transformers	30	40	50
Compensating devices	30	40	50
Series compensations	30	40	50
Control centers	20	20	30
Other installations	20	20	30
Substations	30	40	50
Towers	30	40	50

Analysis 6 in Fig. 4.14 concerns the possible adjustment for local labor costs in the investment stream. Here, we simulate a part a of the total gross investment stream to be constituted of labor costs corrected using the $PLICI$ index used in the study. The labor part ranges from 0% (base case) to 25% of the full investment value.

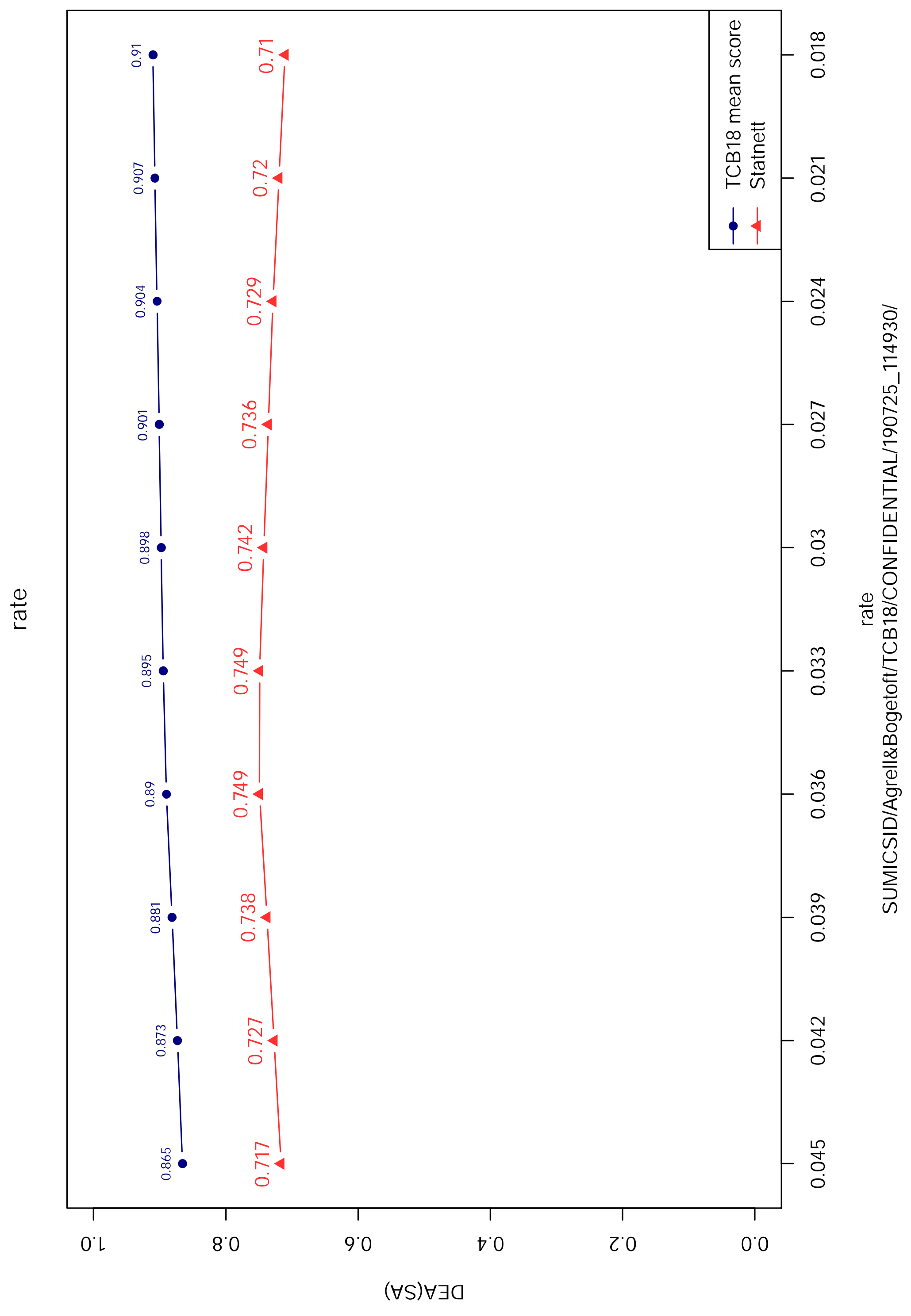

Figure 4.9: Average and operator-specific DEA-score as function of interest rate.

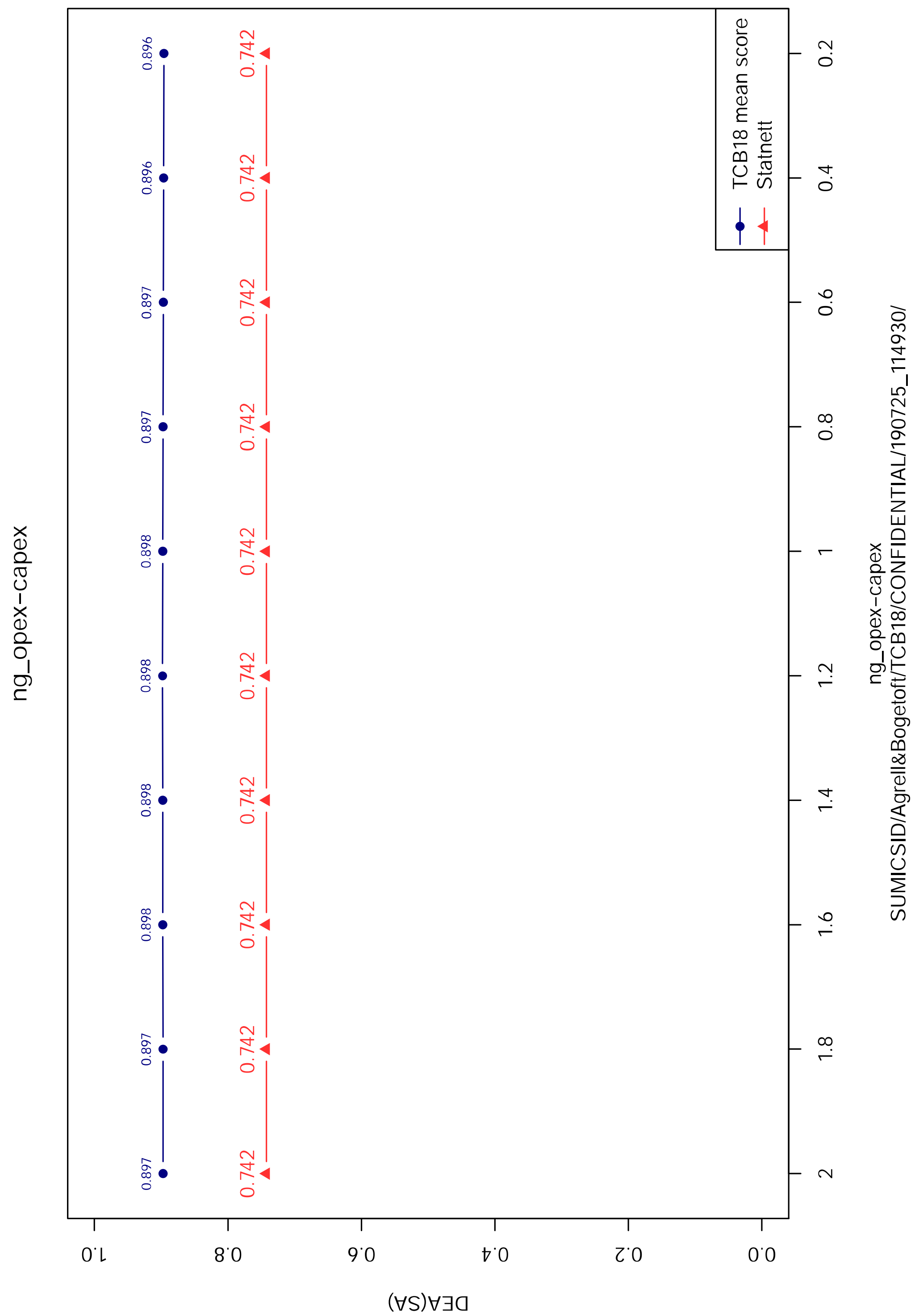

Figure 4.10: Average and operator-specific DEA-score as function of calibration NormGrid opex vs capex (-80pct, + 100pct)

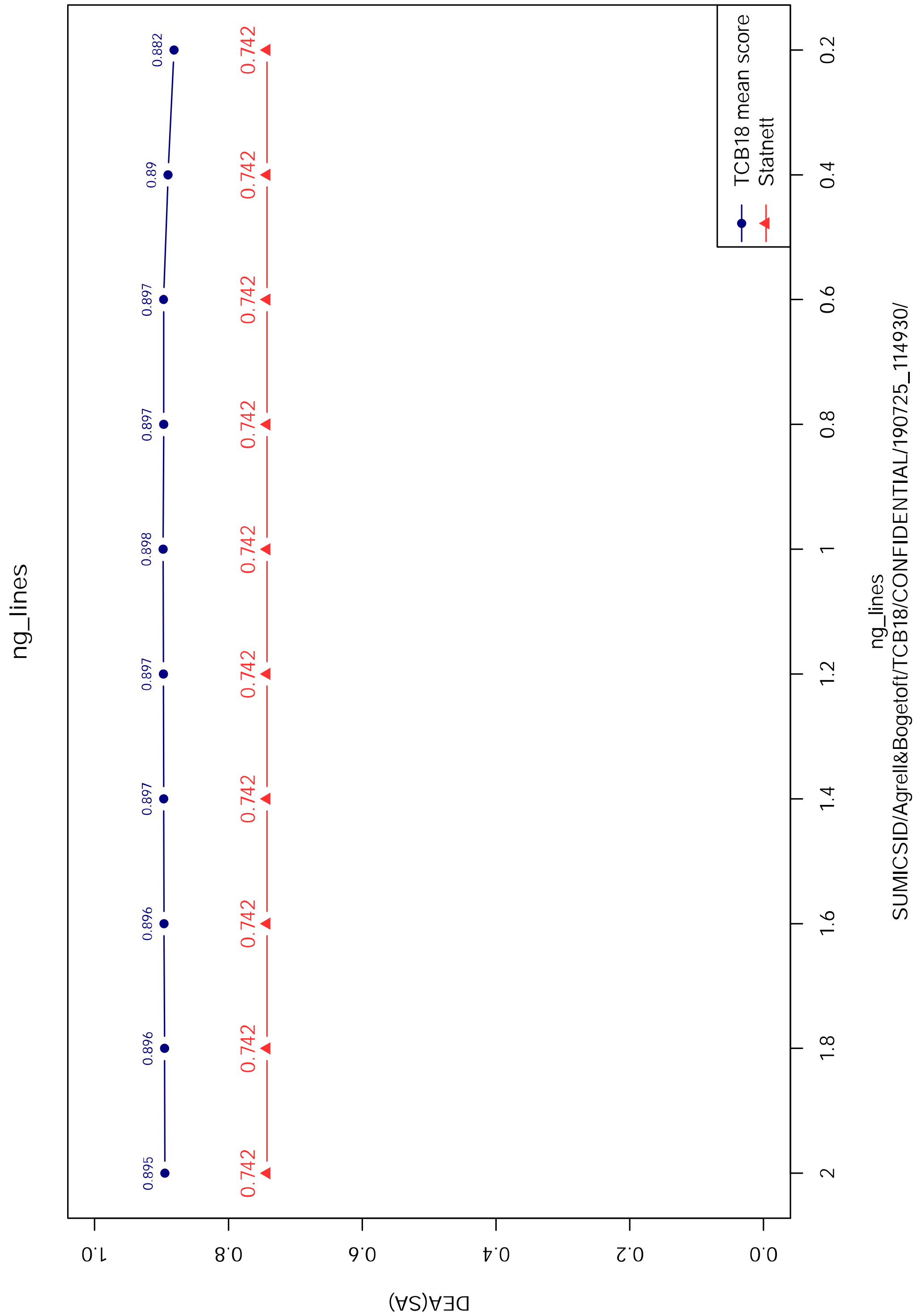

Figure 4.11: Average and operator-specific DEA-score as function of calibration NormGrid for lines (-80pct, + 100pct)

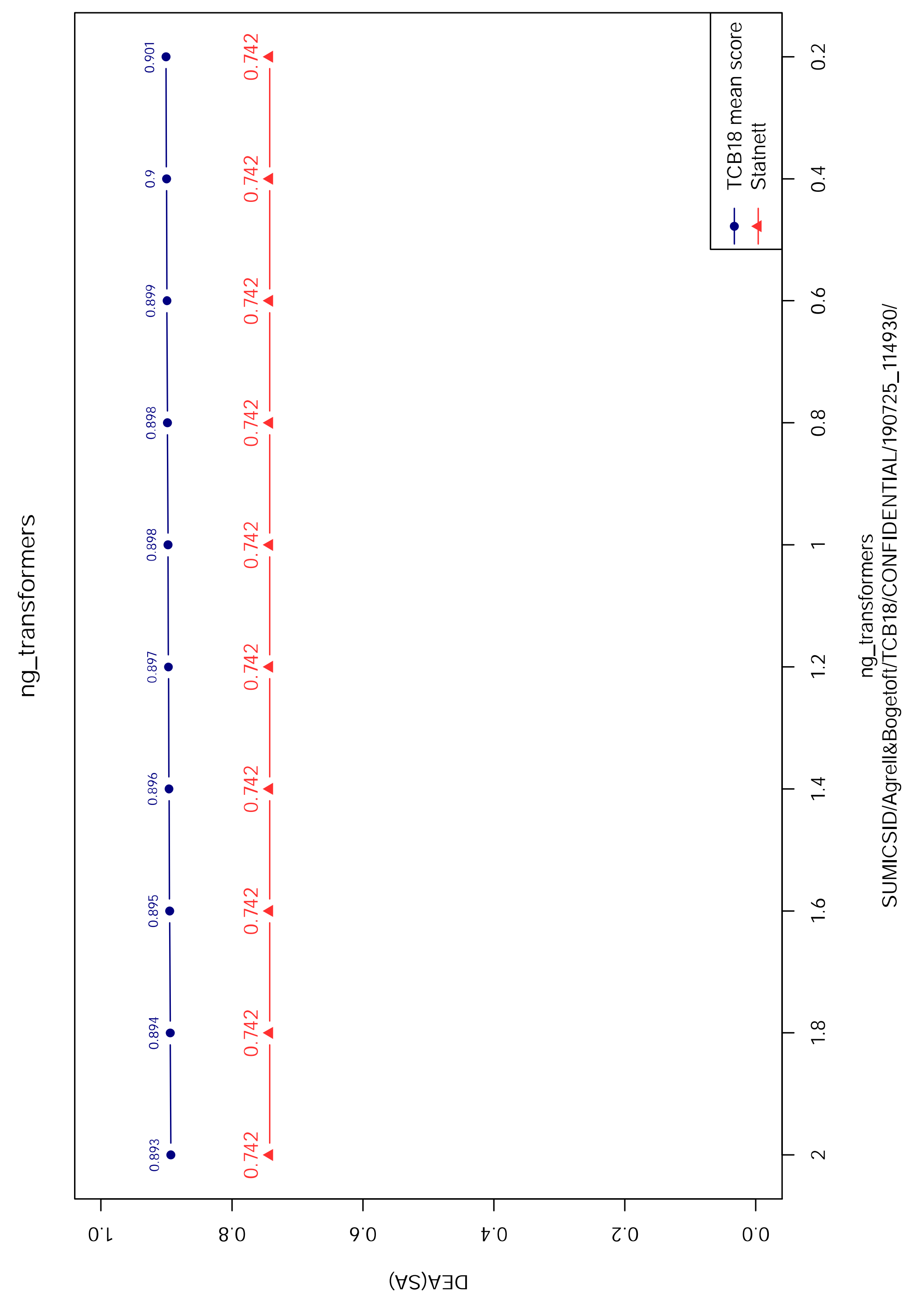

Figure 4.12: Average and operator-specific DEA-score as function of calibration NormGrid for transformers (-80pct, + 100pct)

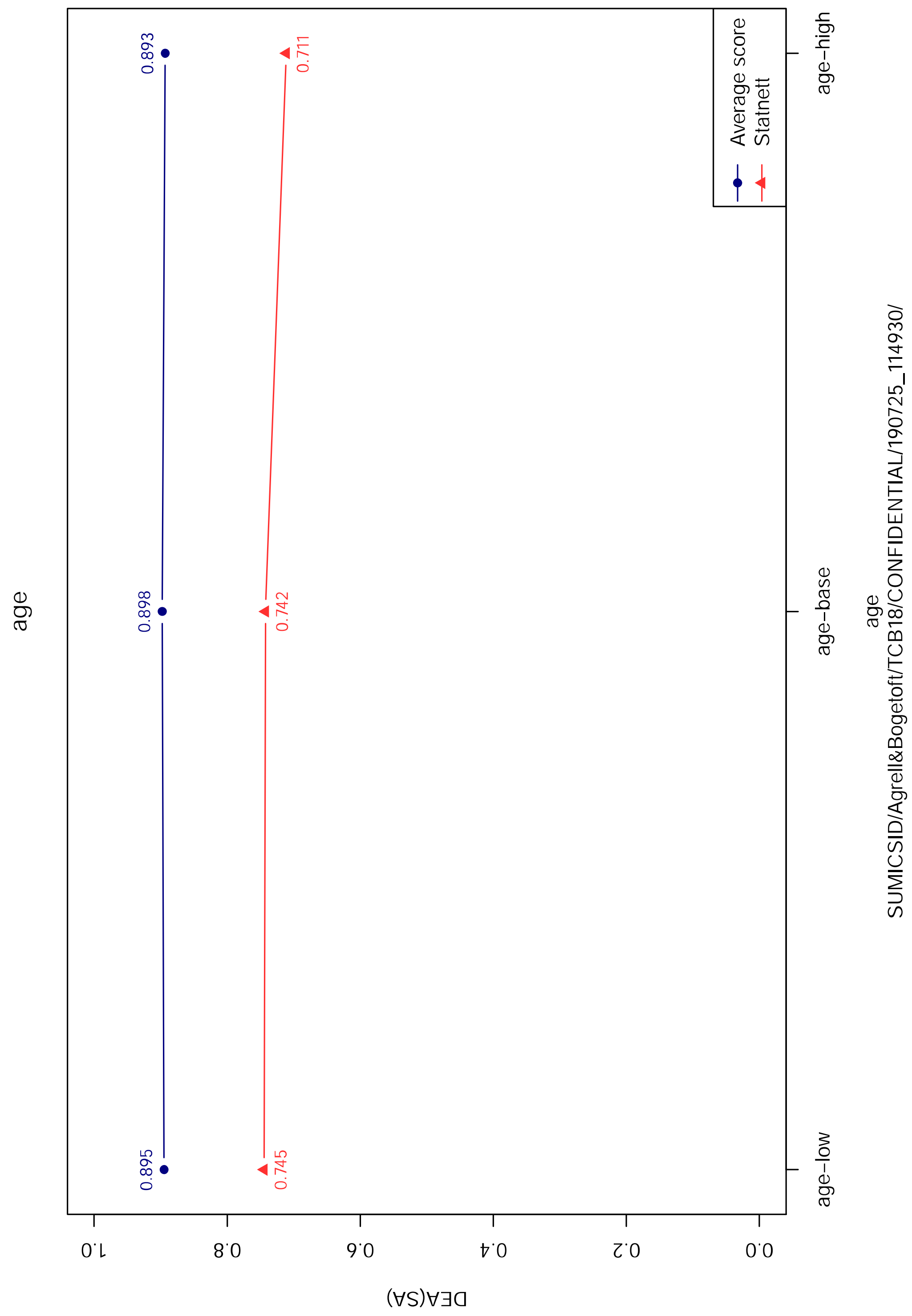

Figure 4.13: Average and operator-specific DEA-score as function of standard lifetimes (age-low = shorter lives, age-base = base case, age-high = longer lives)

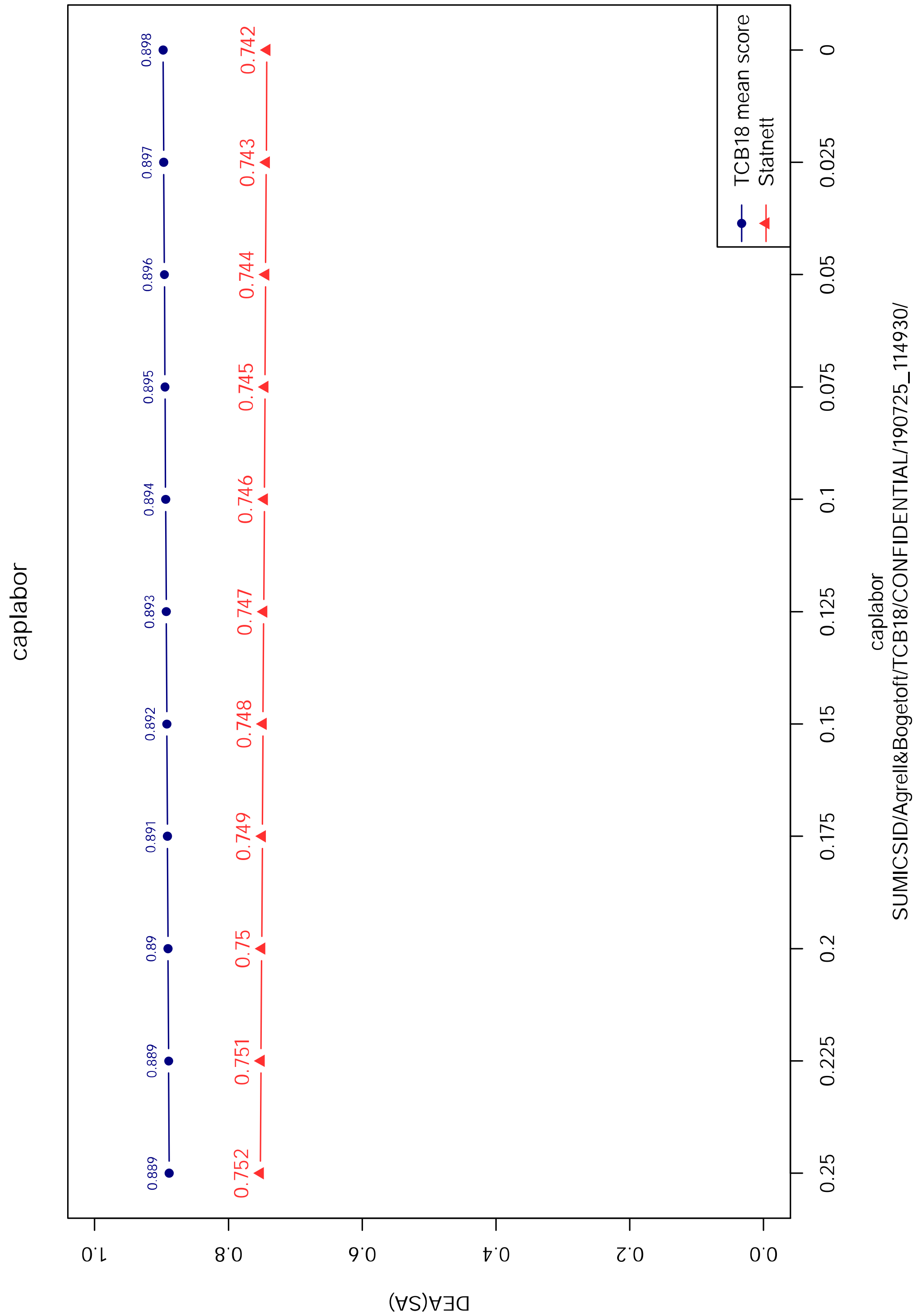

Figure 4.14: Average and operator-specific DEA-score as function of share of investments adjusted for local labor costs (0pct = base case to 25pct).

4.4 Profile

The specific profile of Statnett compared to the other operators in TCB18 is illustrated in Figures 4.15 and 4.16:

- The relative gridsize in Fig. 4.15 depicts the NormGrid sizes of the reference set, scaled such that the mean is set to 100. This analysis gives an impression of the scale differences in the benchmarking.
- The output profile in Fig. 4.16 gives a graphical image of the magnitude of the inputs and outputs for Statnett in red compared to the range of those in TCB18. A value of 100 here corresponds to the highest in the sample, a value of 0 is the smallest, respectively. The median values are indicated in blue.

The routing complexity is analyzed in 4.17 below. Statnett is marked with a red triangle and the share of angular towers below.The figure graphs the circuit length tower on the vertical axis, potentially indicating either a technical choice of smaller towers or topographical challenges (slope, subsoil quality, other obstacles).On the horizontal axis we plot the share of angular towers to the total number of towers. This indicates the routing complexity in terms of landuse and infrastructure obstacles. The output variable yLines.share-steel-angle-mesum is plotted in 4.18 below with Statnett marked as a red triangle. This figure can be compared to the gridsize figure in 4.15, illustrating how routing complexity affects the output variable.

4.5 Age

The age profile of the European operators in comparison to Statnett is illustrated in the Figures 4.19 and 4.20 below.

In Figure 4.19 the ages for all assets in the electricity dataset have been processed as a confidence interval, the yellow box marks the mean in bold black, the box edges are 25% and 75% quartiles and the outer whiskers are limits for one standard deviation up or down, respectively. The mean ages for the assets per type for Statnett are indicated with a red triangle and a (rounded) number. A circle to the left or right of the confidence interval box indicates an outlier.

In Figure 4.20 we investigate the prevalence of very old (pre-1973) assets that are still used in 2017. The average share of capital for different asset types (symbols) is graphed on the horizontal axis. The share of capital for pre-1973 assets is given on the vertical axis. The respective asset ages for Statnettare depicted using red symbols, the blue symbols depict the mean age and shares, respectively, in the TCB18 project. If the red symbols are located north-east on the corresponding blue symbol, it means that your assets are both relatively older and also that the asset type represents a higher importance than for the mean operator.

4.6 Cost analysis

In this section we analyze the staff profile, the functional costs and the overhead allocation share for Statnett compared to the electricity operators in TCB18. The cost analysis is purely informative and does not intervene as such in the benchmarking. In Fig.4.21 the mean staff intensity SI_f for all operators is presented using the NormGrid per activity f:

$$SI_f = mean_k\{\frac{Staff_{fk}}{NormGrid_k}\} \tag{4.2}$$

where $Staff_{fk}$ is the staff count (fte) for activity f for operator k and $NormGrid_k$ is the sum of the NormGrid for operator k in the corresponding year. This intensity is then used to obtain a size-adjusted comparator for the mean staff in the sample, SC_{fk}, scaled to the size of Statnett, i.e. $k = 190$ here:

$$SC_{f,190} = SI_f NormGrid_{190} \tag{4.3}$$

In Fig 4.22 the allocation key for indirect expenditure (I) is based on total expenditure per activity excluding energy and depreciation, i.e. the graph can also be interpreted as the relative shares of expenditure by function. In Fig 4.23 we graph the actual allocation of indirect expenditure to the benchmarked activities T,M,P per operator, along with the mean allocation in the sample.

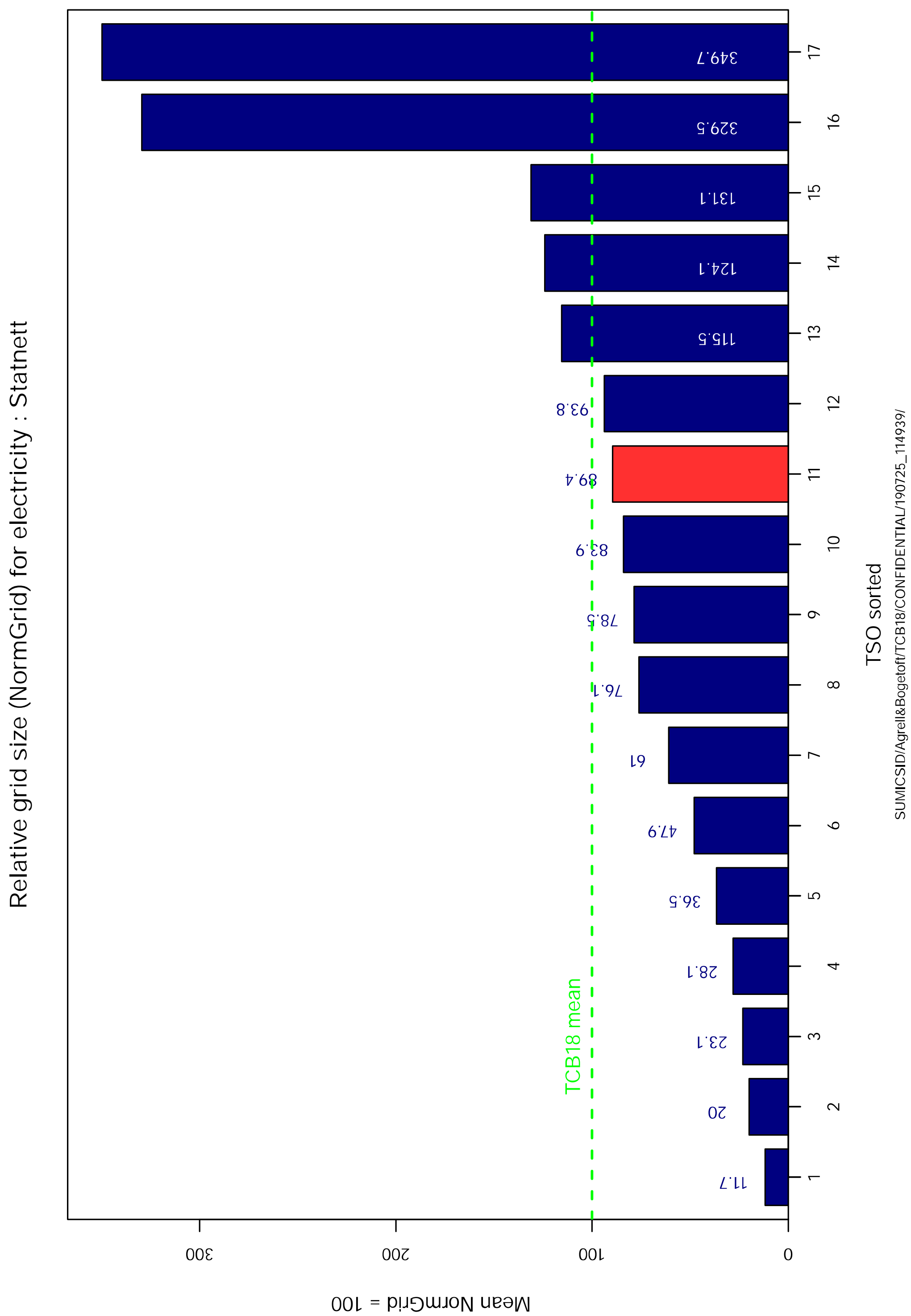

Figure 4.15: Relative gridsize in TCB18, (100=mean level in 2017).

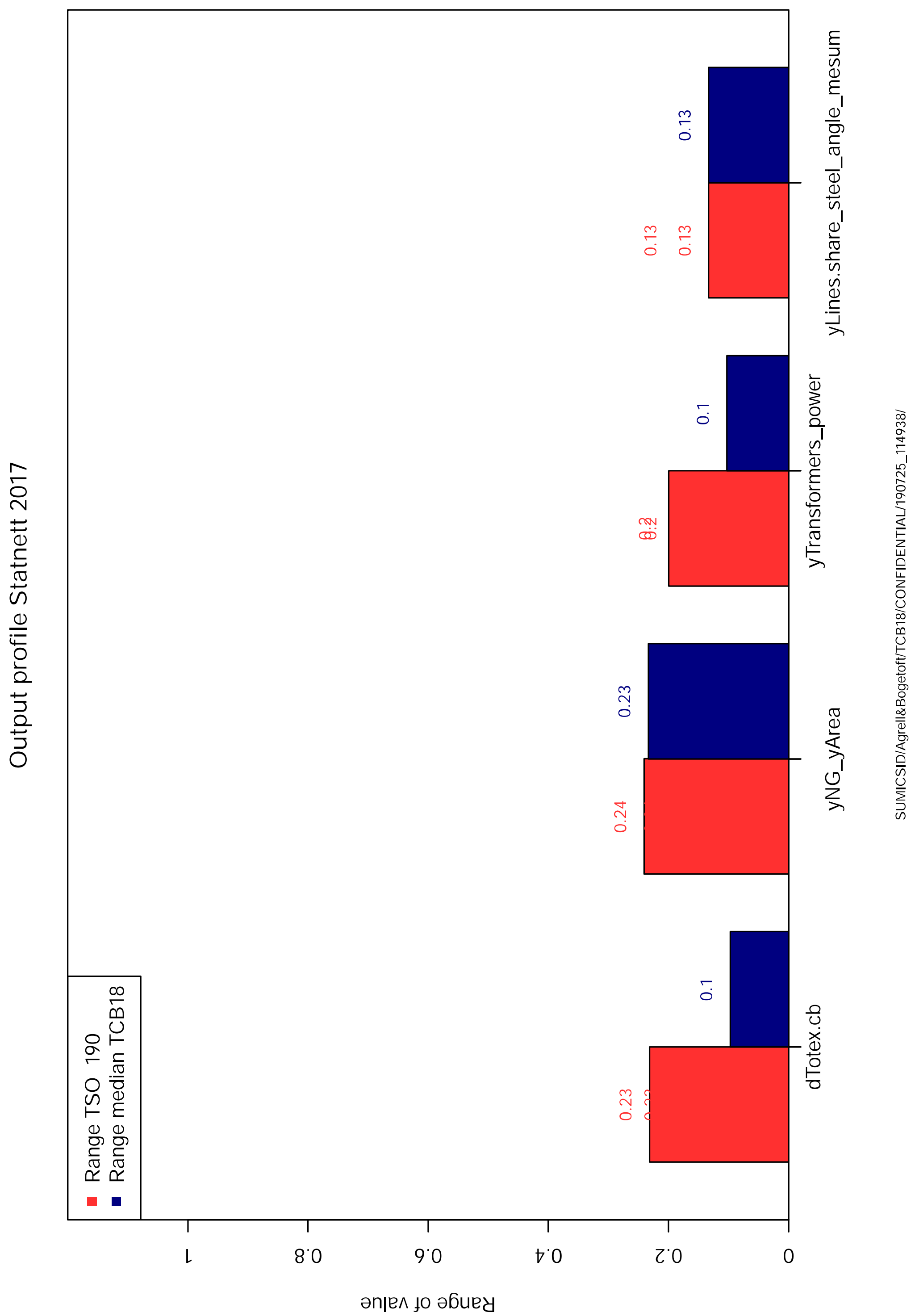

Figure 4.16: Inputs and outputs compared to median range in TCB18 (0.0 = minimum, 1.0 = maximum).

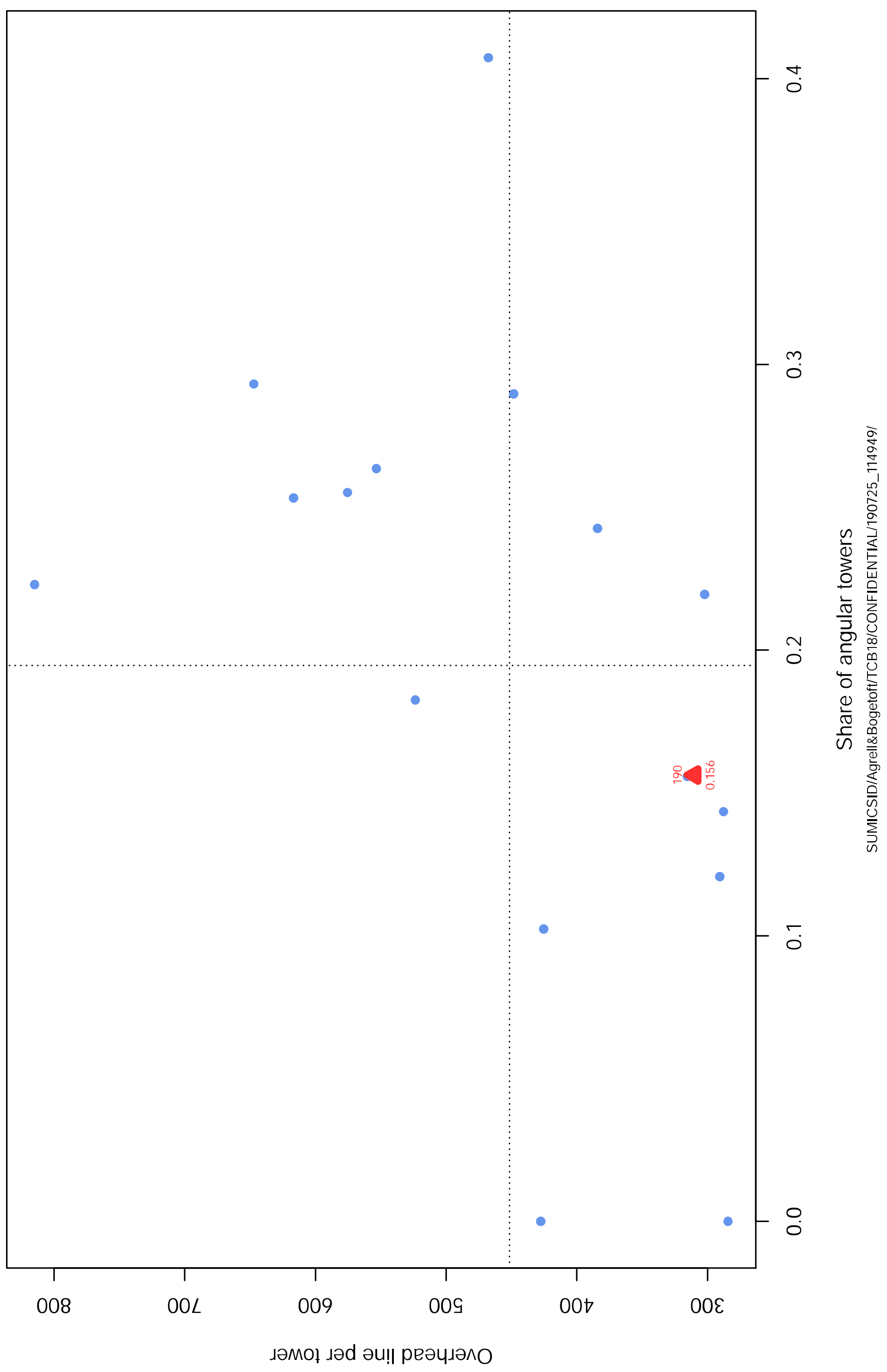

Figure 4.17: Linelength per tower and share of angular towers 2017.

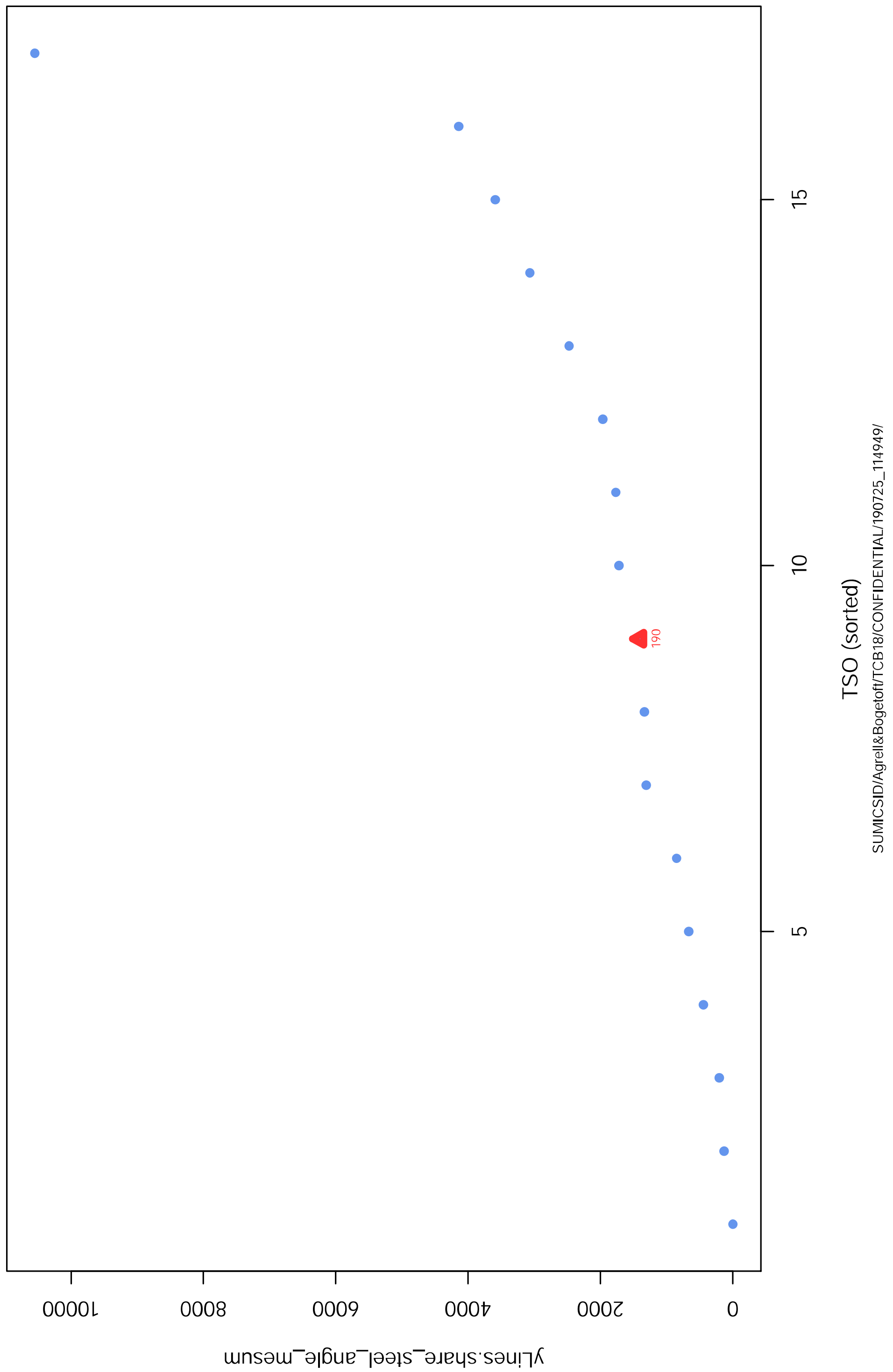

Figure 4.18: Output yLinesShareSteelAngleMesum, sorted in absolute value.

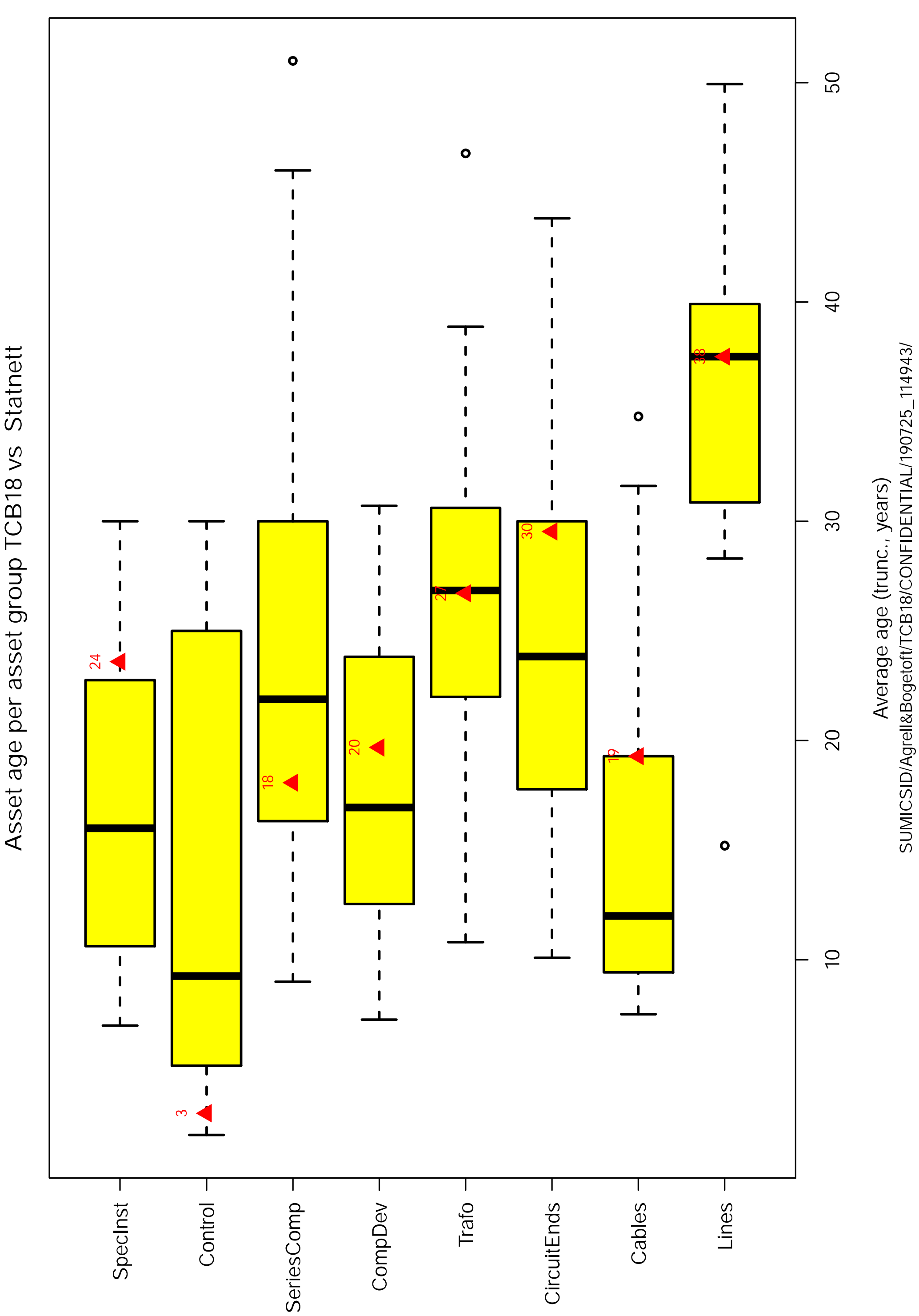

Figure 4.19: Asset ages (confidence interval) for all TCB18 and mean age for a specific operator.

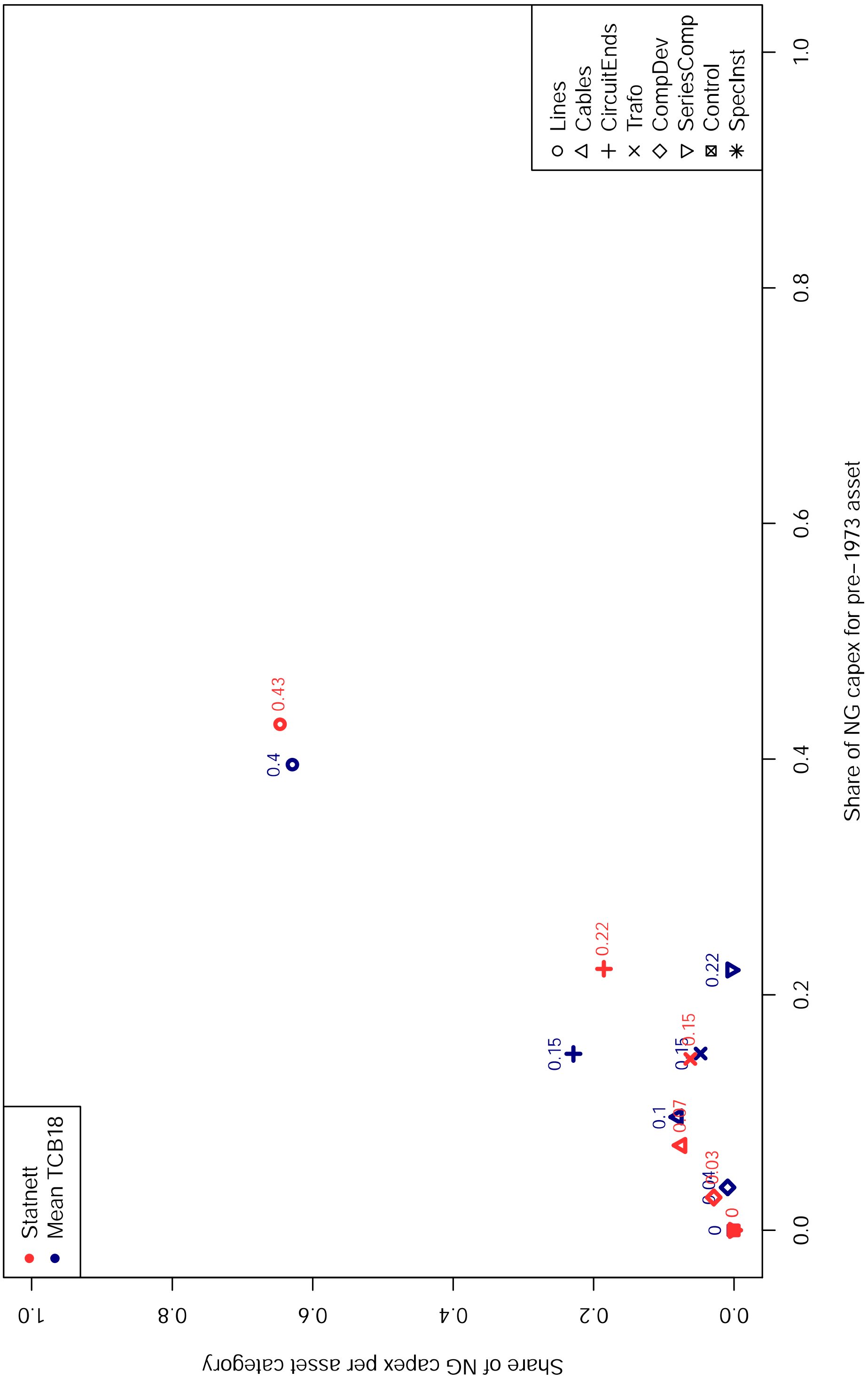

Figure 4.20: Share of total capital and share for old assets per asset category.

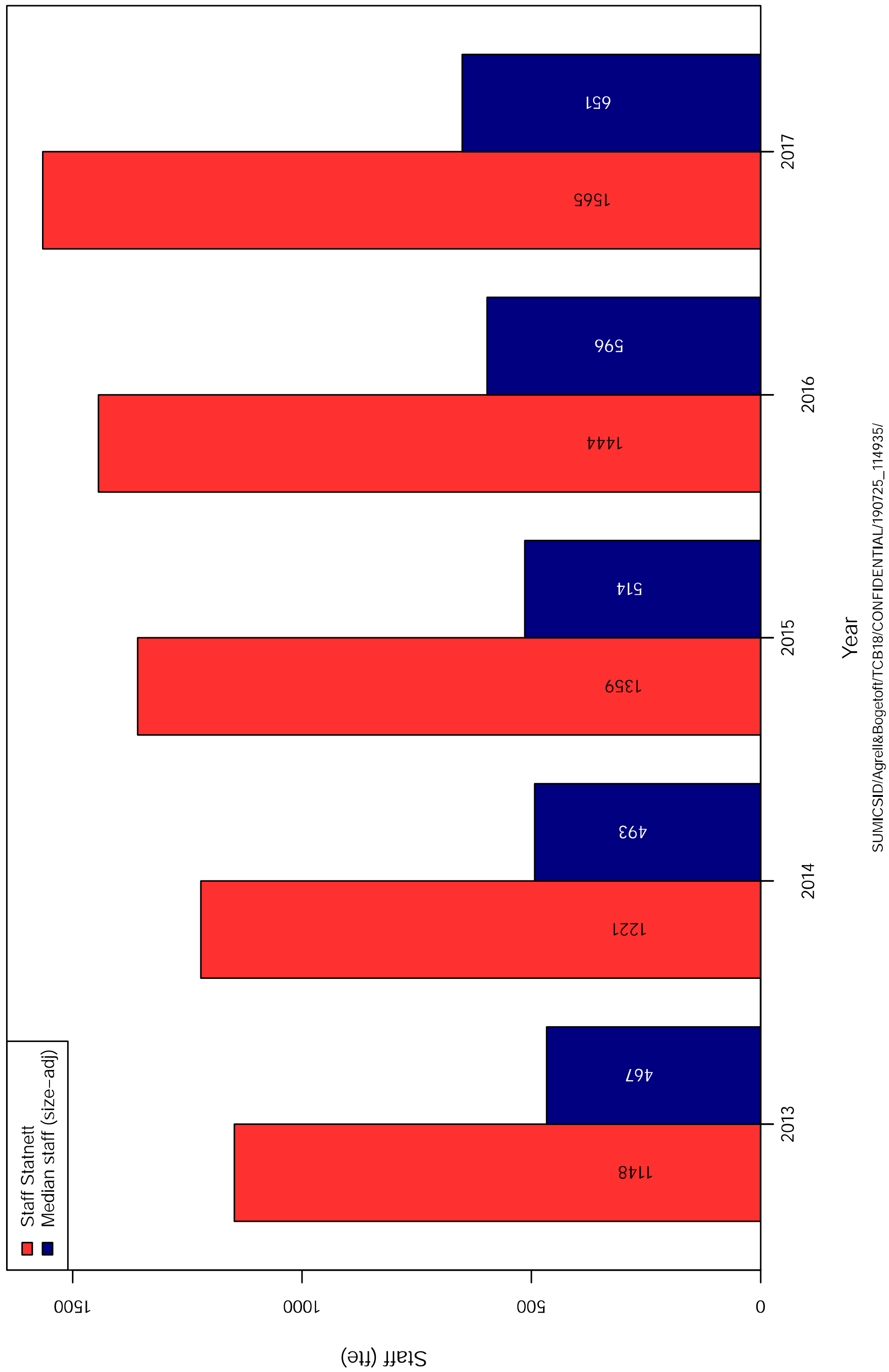

Figure 4.21: Actual staff (fte) compared to size-adjusted level for a median operator in TCB18.

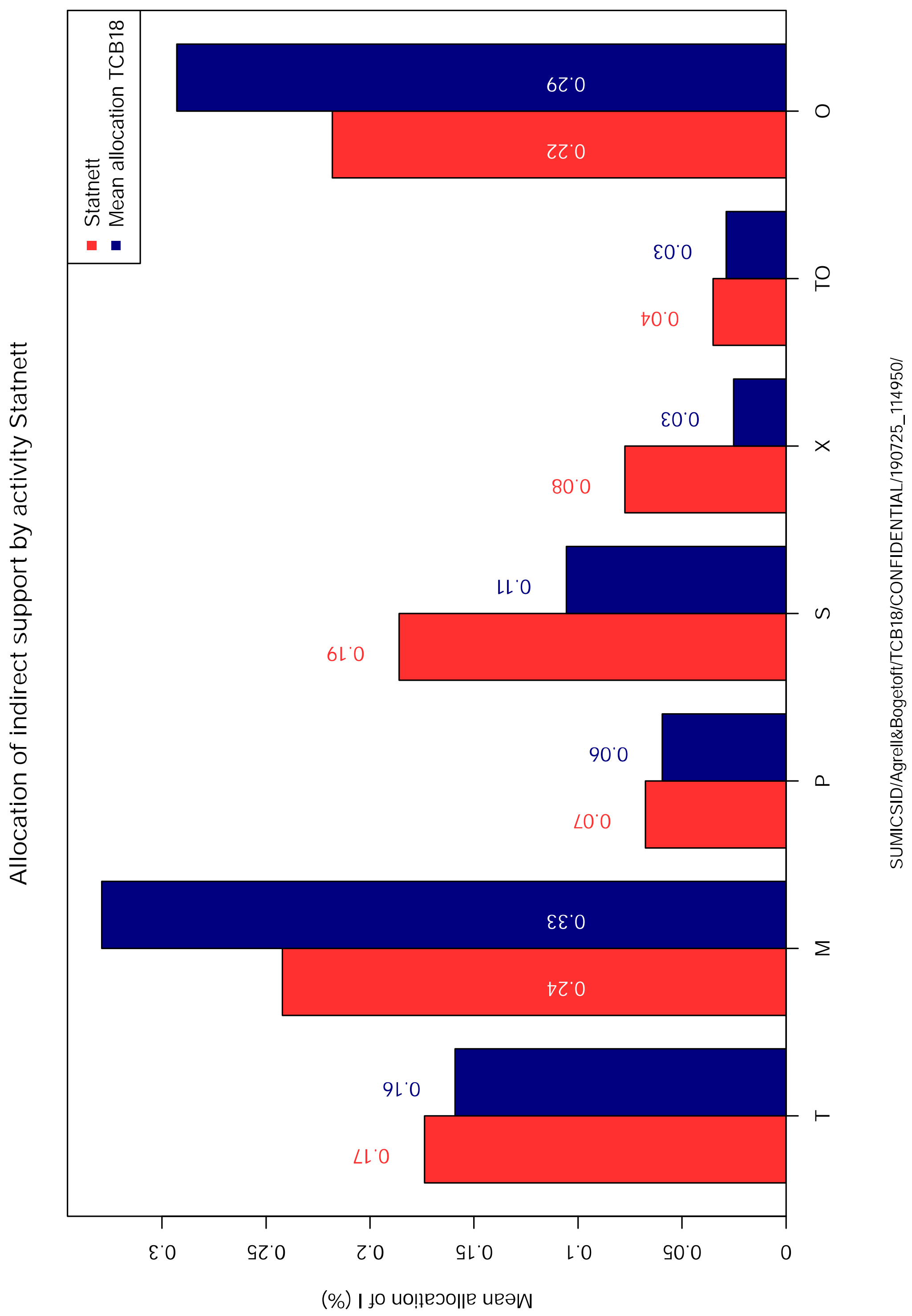

Figure 4.22: Allocation of overhead by function, mean and by operator, 2017.

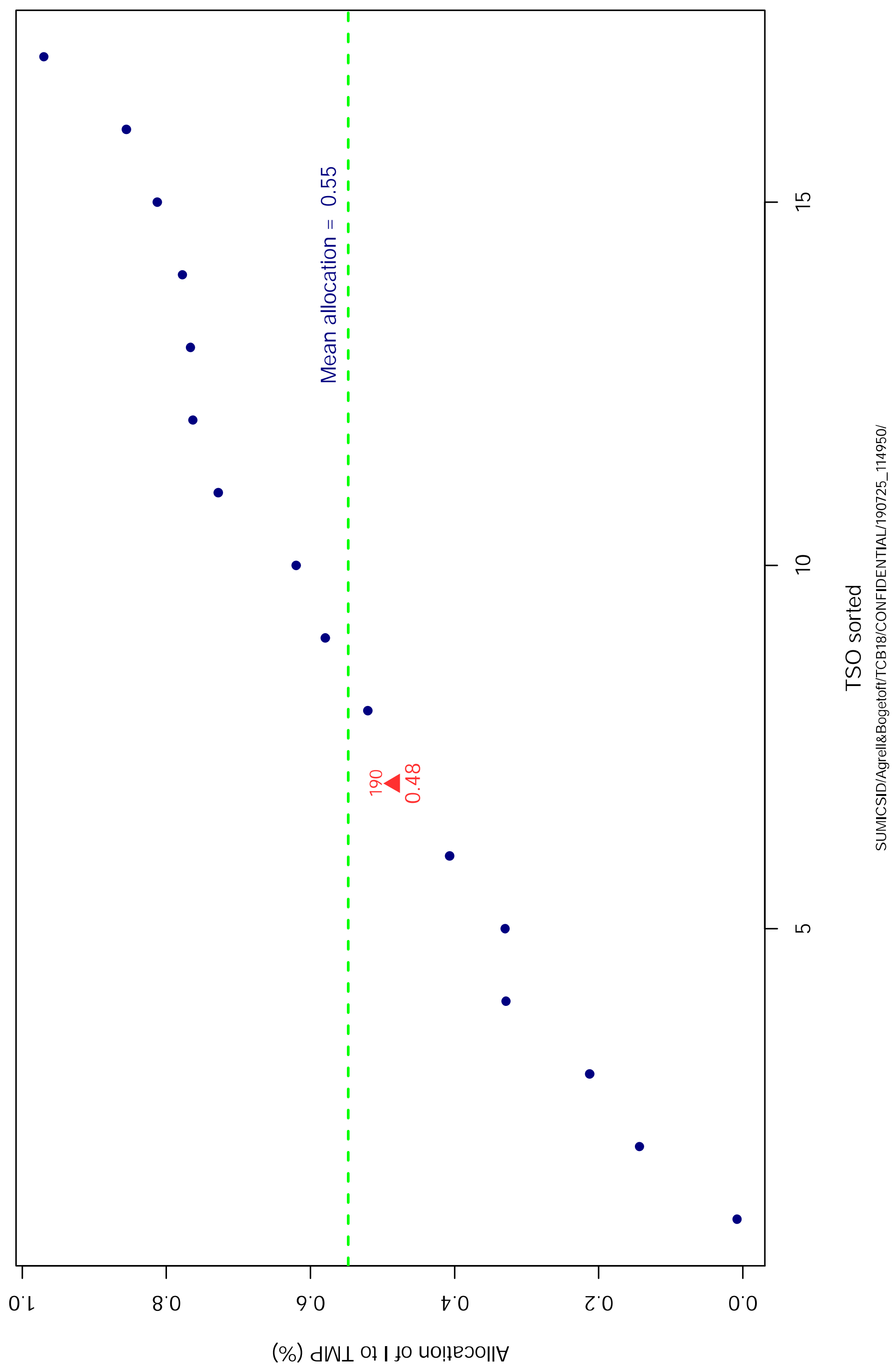

Figure 4.23: Overhead allocation (per cent) to TMP activities in TCB18.

Chapter 5

Second-stage analysis

In order to investigate whether some potentially relevant variables have been omitted in the final model specification, a so-called second stage analysis has been performed. The idea of the second stage analysis is to investigate if some of the remaining variation in performance can be explained by any of the unused cost drivers. This is routinely done by regressing the efficiency scores on these variables in turn. The second-stage regression is concretely regressing an omitted factor, ψ against the DEA-score, i.e.

$$DEA_{NDRS} = \beta_0 + \beta_1 \psi + \epsilon \tag{5.1}$$

The result of such an exercise is given in Table 5.1 below. A small value of the p-statistics or equivalent a high t-value would indicate that the parameter ψ is interesting. $maxImpact$ indicates the coefficient value β_1 multiplied with the maximum range for the variable concerned, $\max(\psi) - \min(\psi)$.

As seen from Table 5.1, no parameter is significant at the 5% or 1% levels, indicating that the dimensions herein are considered in the model and do not merit specific post-run corrections.

Table 5.1: Second-stage analysis, final model electricity

Parameter	t-value	p-value	maxImpact	Sign-5%	Sign-1%
yNG	-0.298	0.770	-0.034		
yNG_zSlope	-0.167	0.870	-0.020		
yNG_zLandhumidity	-0.327	0.748	-0.037		
yNG_zGravel	-0.314	0.758	-0.035		
yNG_yLines.share_totex_angle.vsum_lmrob_corr	-0.201	0.843	-0.023		
yNG_yLines.share_circuit_angle.vsum_lmrob_corr	-0.248	0.807	-0.029		
yNG_yAreaShare.forest_lmrob_corr	-0.341	0.738	-0.038		
yNG_yShare.area.wetland.tot_lmrob_corr	-0.330	0.746	-0.038		
yNG_yShare.area.urban.tot_lmrob_corr	-0.368	0.718	-0.042		
yNG_yShare.area.infrastructure.tot_lmrob_corr	-0.370	0.717	-0.041		
yNG_yShare.area.cropland.tot_lmrob_corr	-0.386	0.705	-0.045		
yNG_yShare.area.woodland.tot_lmrob_corr	-0.319	0.754	-0.036		
yNG_yShare.area.grassland.tot_lmrob_corr	-0.275	0.787	-0.032		
yNG_yShare.area.shrubland.tot_lmrob_corr	-0.316	0.757	-0.036		
yNG_yShare.area.wasteland.tot_lmrob_corr	-0.402	0.694	-0.046		
yNG_zHumidity.wwpi_lmrob_corr	-0.477	0.640	-0.054		
yNG_zRugged_lmrob_corr	-0.310	0.761	-0.035		
yNG_zGravel_S_mean_lmrob_corr	-0.277	0.786	-0.032		
yNG_zGravel_T_mean_lmrob_corr	-0.282	0.782	-0.033		
yNG_yClimate.icing_lmrob_corr	-0.238	0.815	-0.027		
yNG_yClimate.heat_lmrob_corr	-0.396	0.698	-0.046		
yNG_zDensity.railways_lmrob_corr	-0.321	0.753	-0.036		
yLines_ehv	-0.827	0.421	-0.099		
yLines_hv	0.855	0.406	0.114		
yTowers_angular	-0.126	0.901	-0.017		
yTowers_angulars	-0.184	0.857	-0.026		
yTowers_steel	-0.530	0.604	-0.072		
yLines.share_totex_angle.vsum	0.083	0.935	0.010		
yLines.share_circuit_angle.vsum	0.385	0.706	0.054		
age1y	-0.228	0.822	-0.033		
age_meany	-0.120	0.906	-0.017		
dist_coast	0.853	0.407	0.080		
near_coast	-0.842	0.413	-0.071		

Chapter 6

Cost development

In this chapter the dynamic cost development for Statnett compared to that for the electricity operators in TCB18 is analyzed, first by activity, then by cost type for the benchmarked activities T,M,P. The graph for the general development, both in terms of grid growth (NormGrid) and in terms of expenditure, are drawn with dashed lines. The line for Statnett is drawn as a solid line if the costs are reported for several years, otherwise the graphs are only providing mean information.
In the activity cost graphs, a solid green line is indicating the base line of one (no change in expenditure). All cost data are adjusted for inflation using 2017 as base year, the analysis thus concerns real cost development.

This information is useful to consider specific sources of efficiency and in-efficiency compared to the comparators, considering the earlier analyses for profile, age and sensitivity.

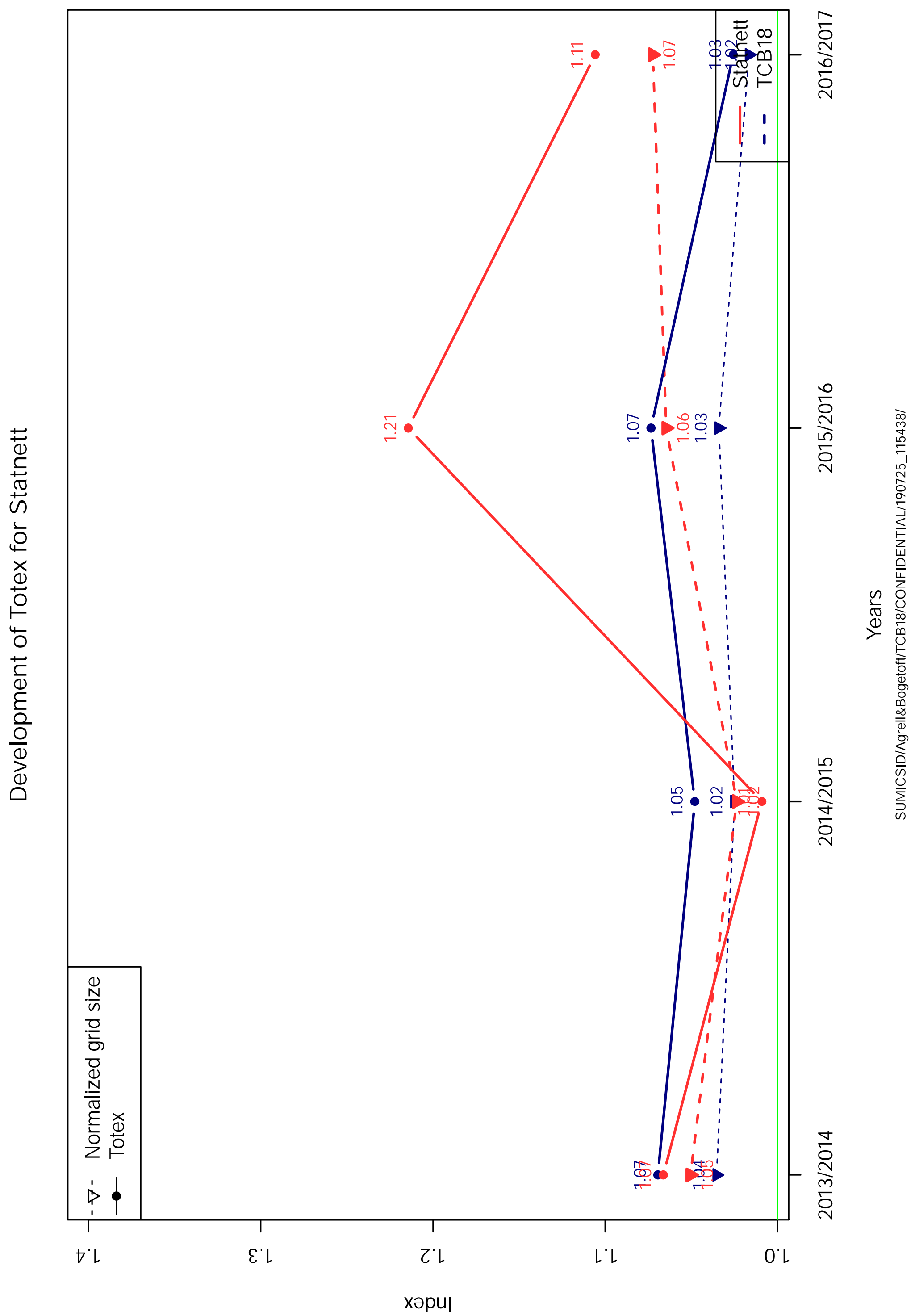

Figure 6.1: Totex development (TMP)

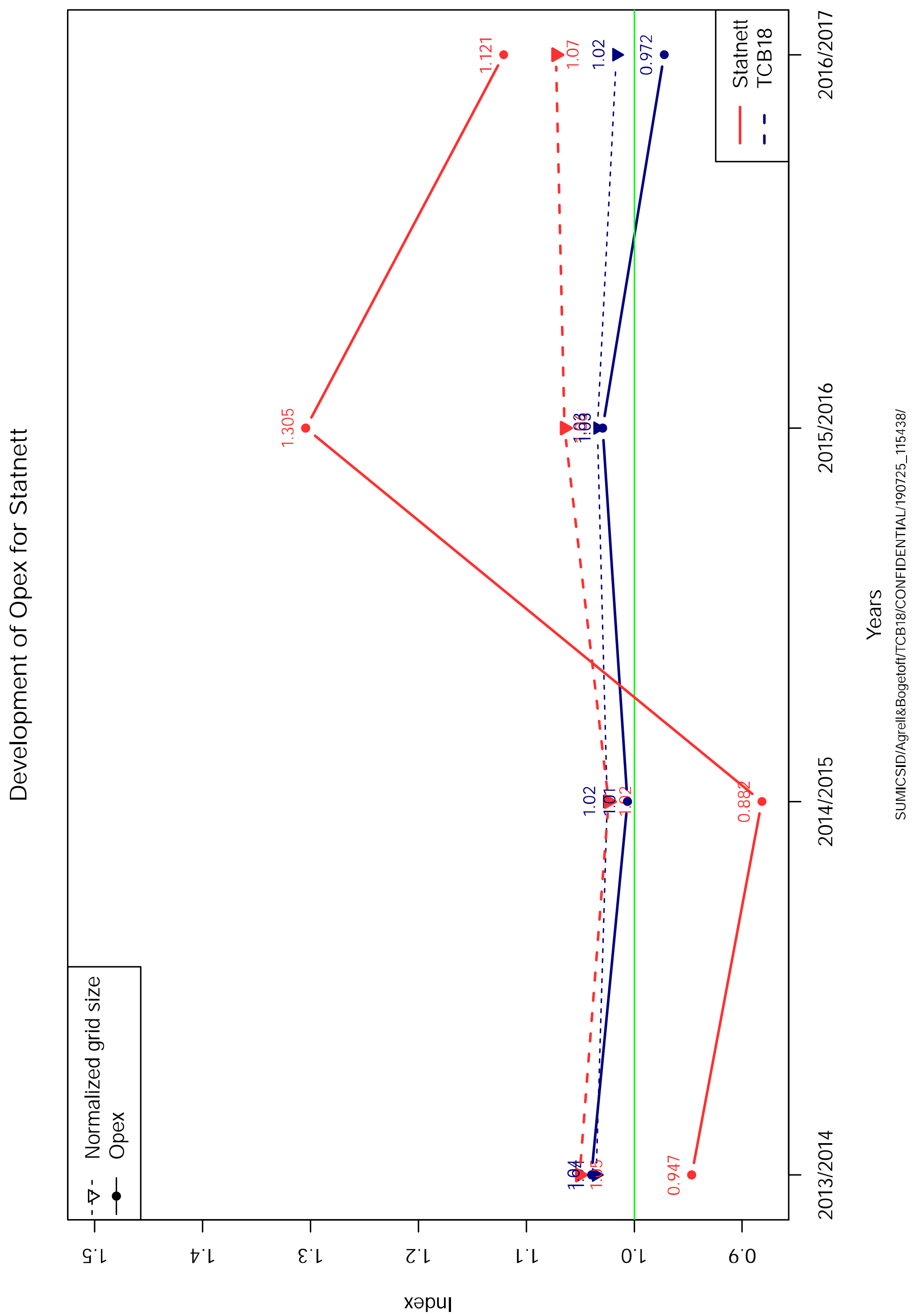

Figure 6.2: Opex development (TMP)

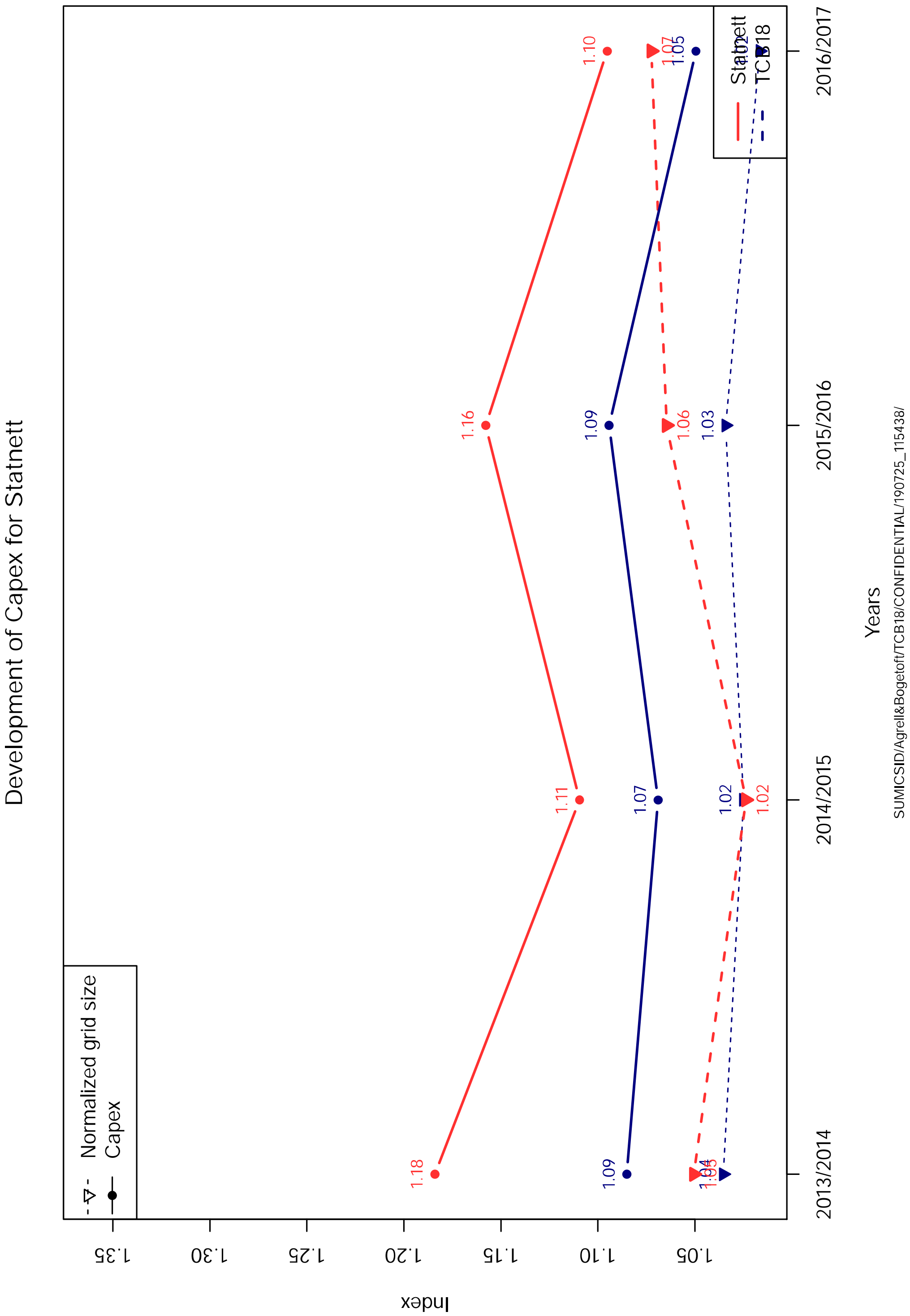

Figure 6.3: Capex development

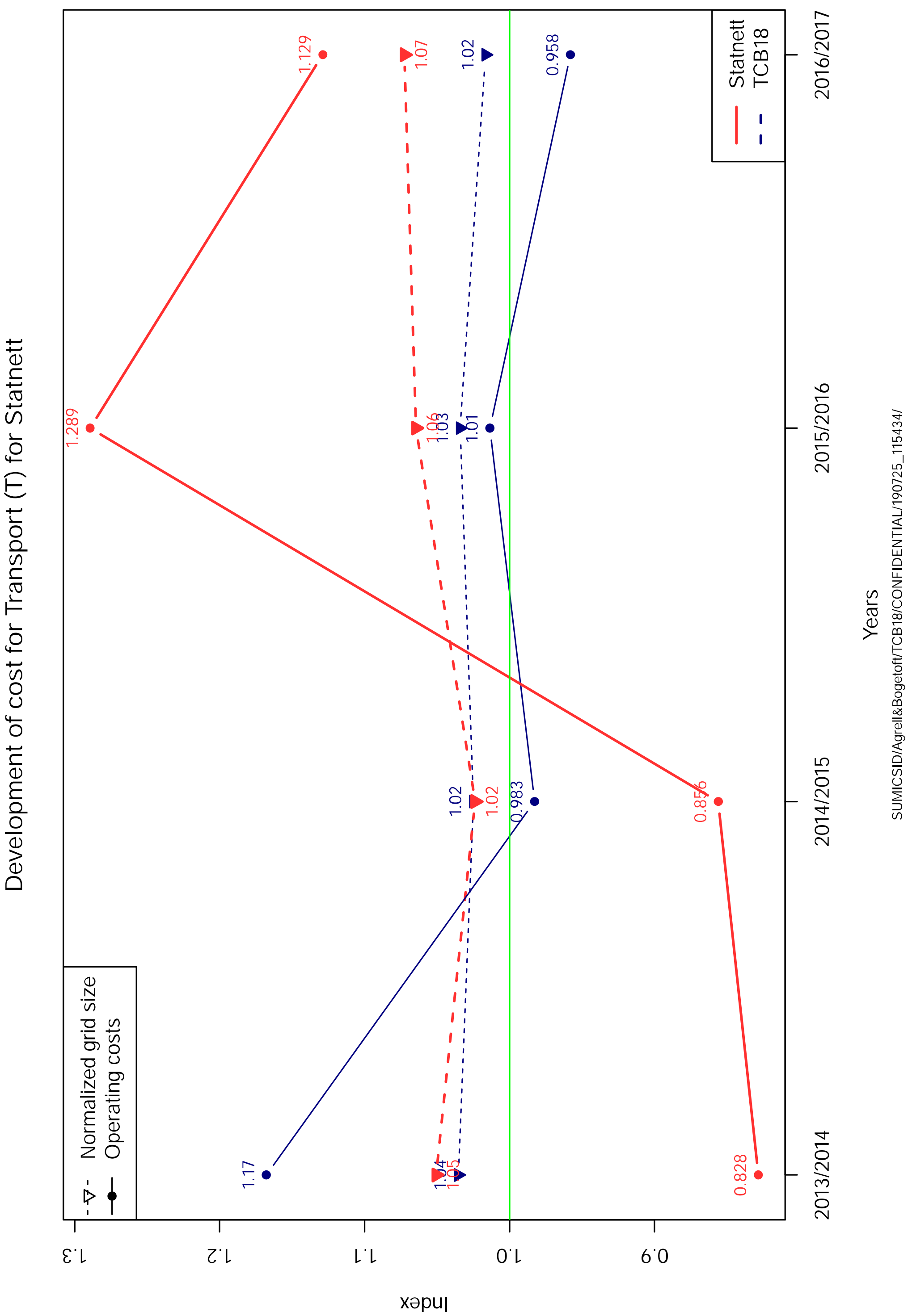

Figure 6.4: Cost development transport (T) vs grid growth.

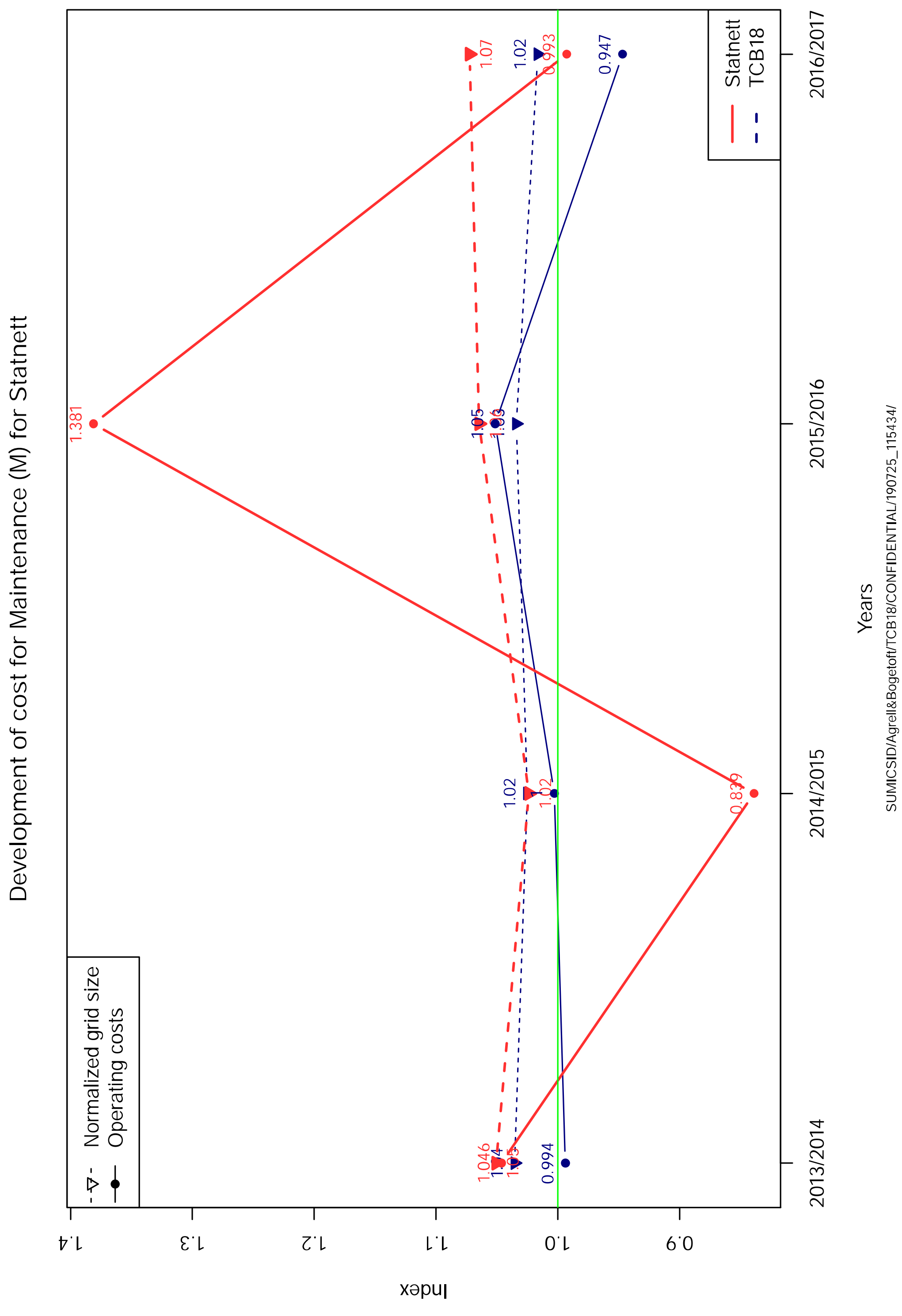

Figure 6.5: Cost development maintenance (M) vs grid growth.

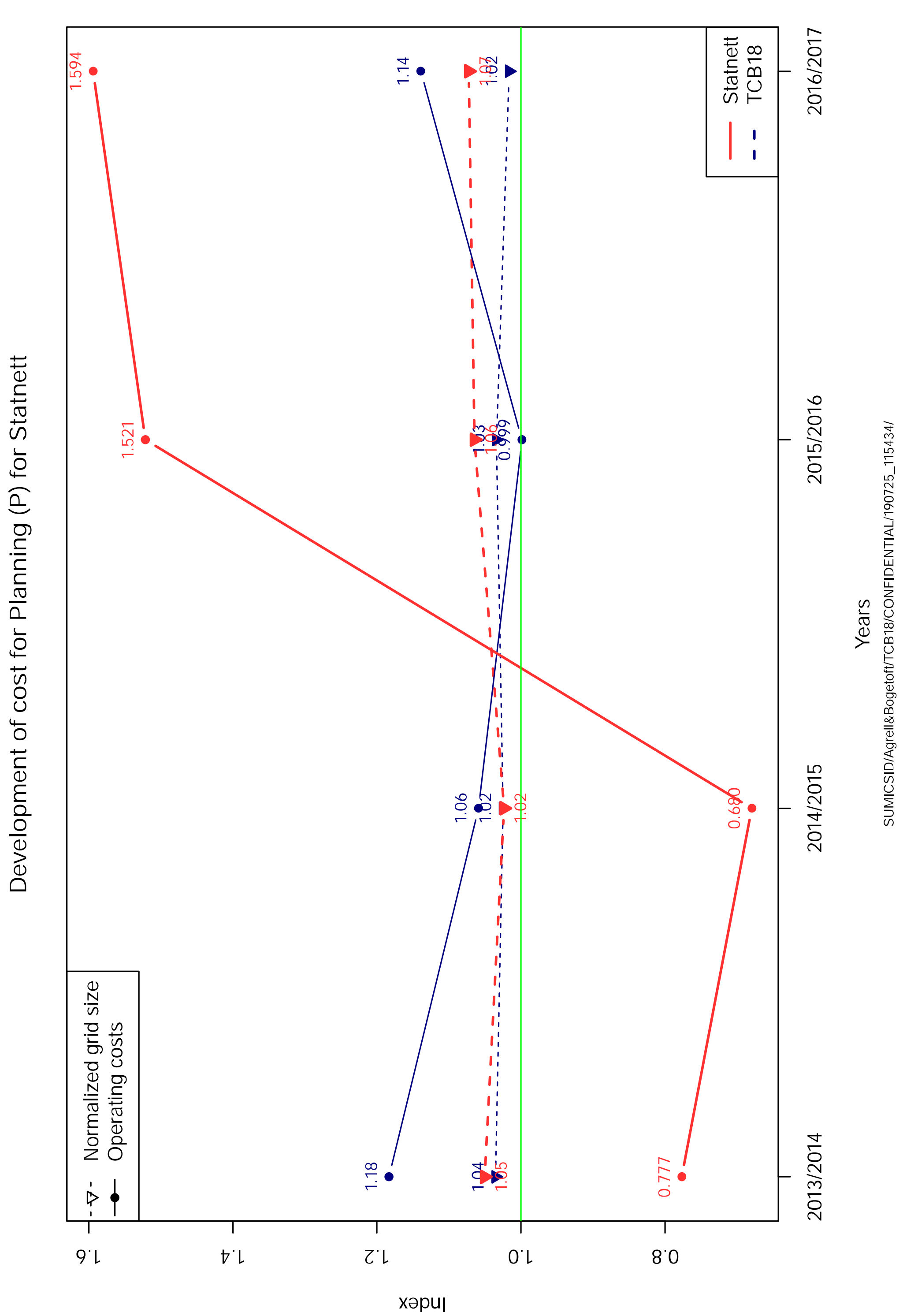

Figure 6.6: Cost development planning (P) vs grid growth.

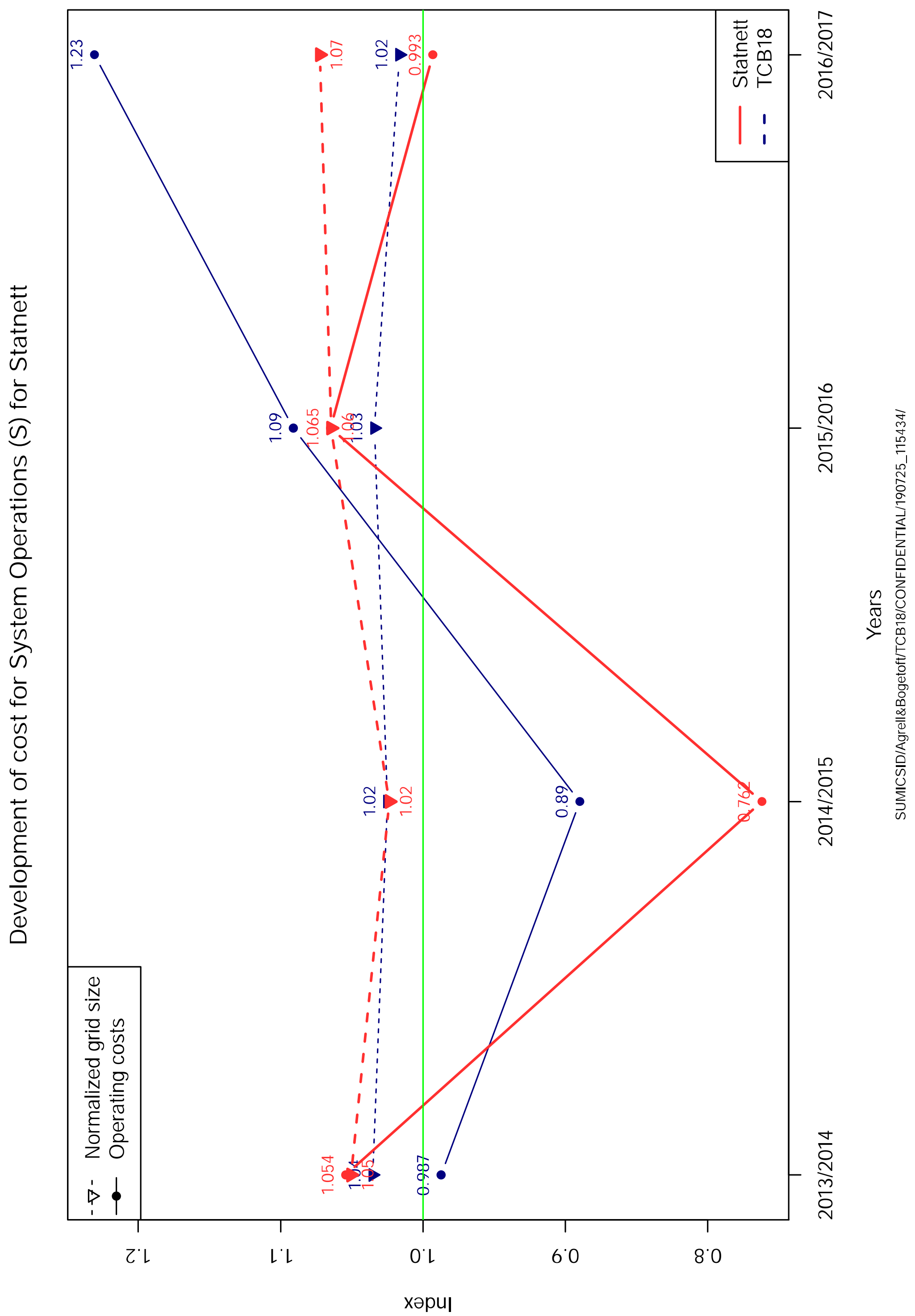

Figure 6.7: Cost development system operations (S) vs grid growth.

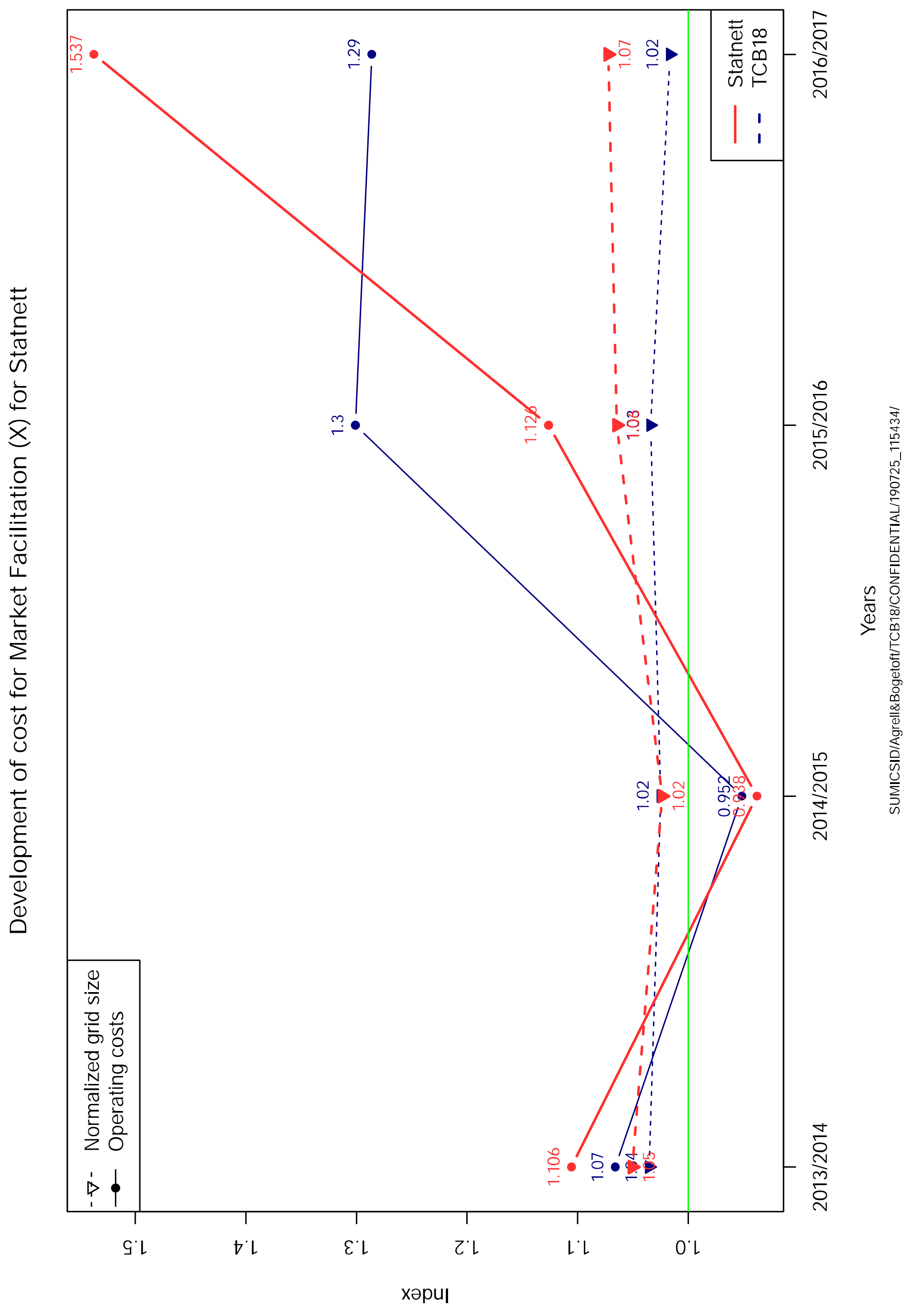

Figure 6.8: Cost development market facilitation (X) vs grid growth.

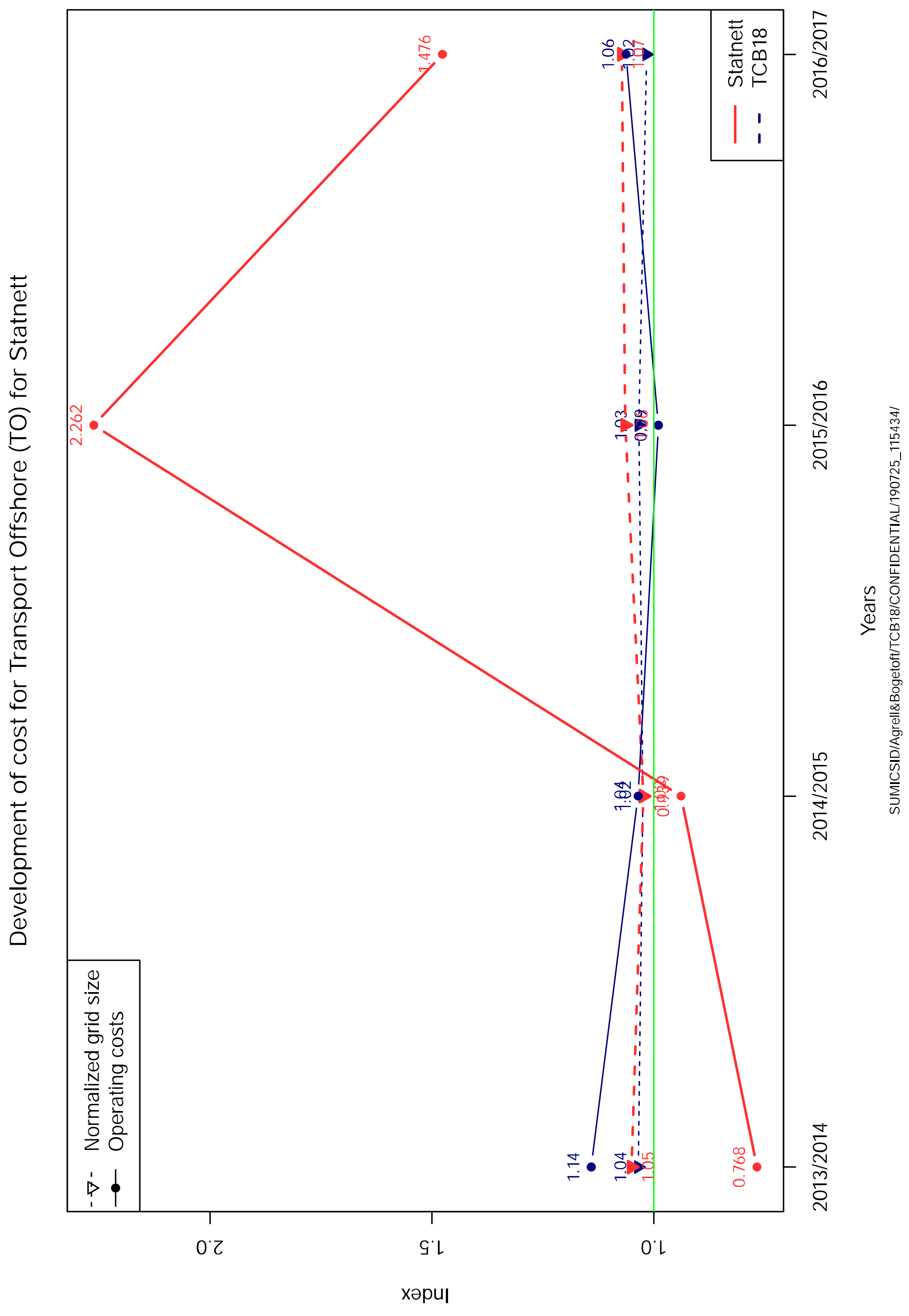

Figure 6.9: Cost development offshore transport (TO) vs grid growth.

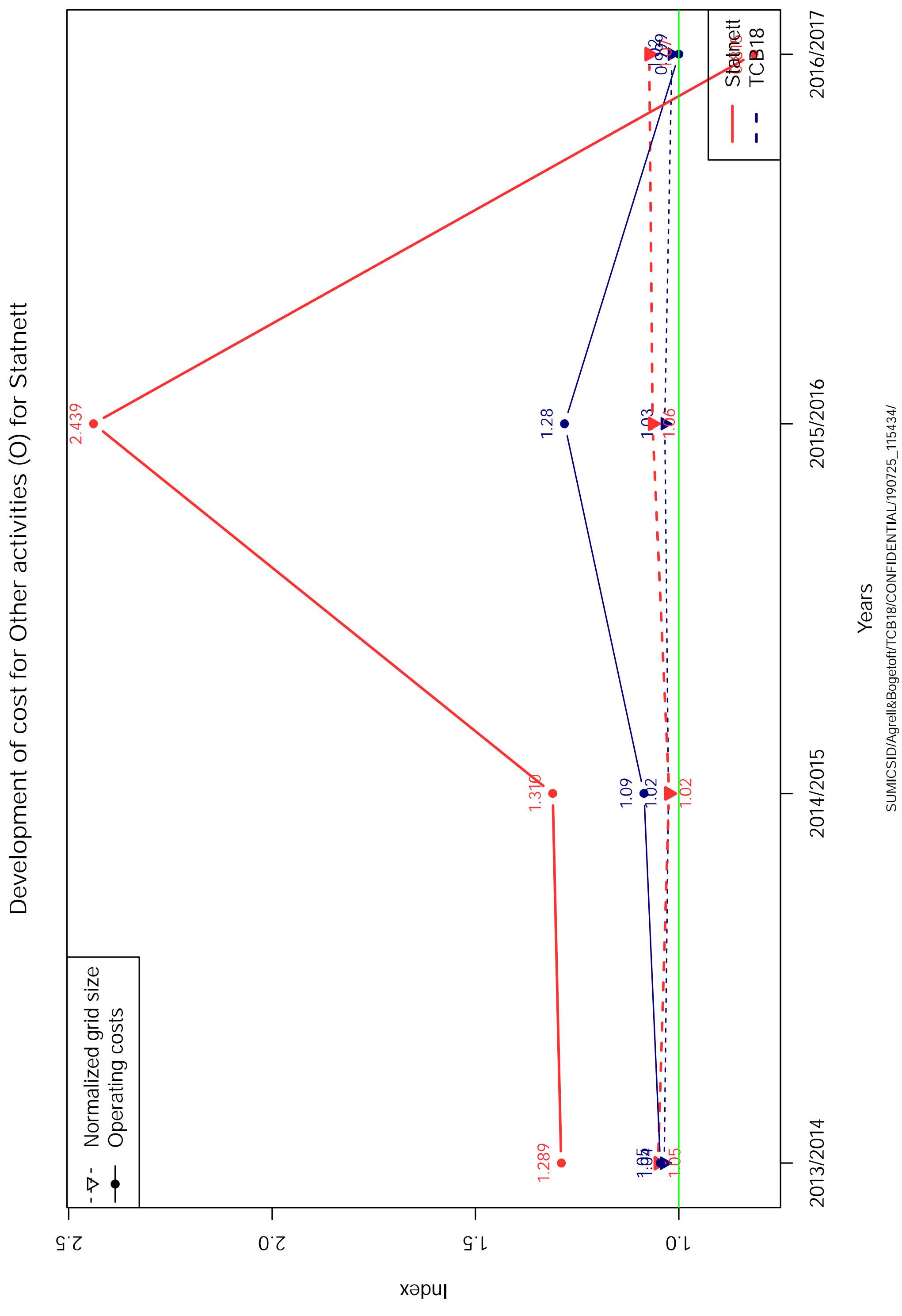

Figure 6.10: Cost development out-of-scope (O) vs grid growth.

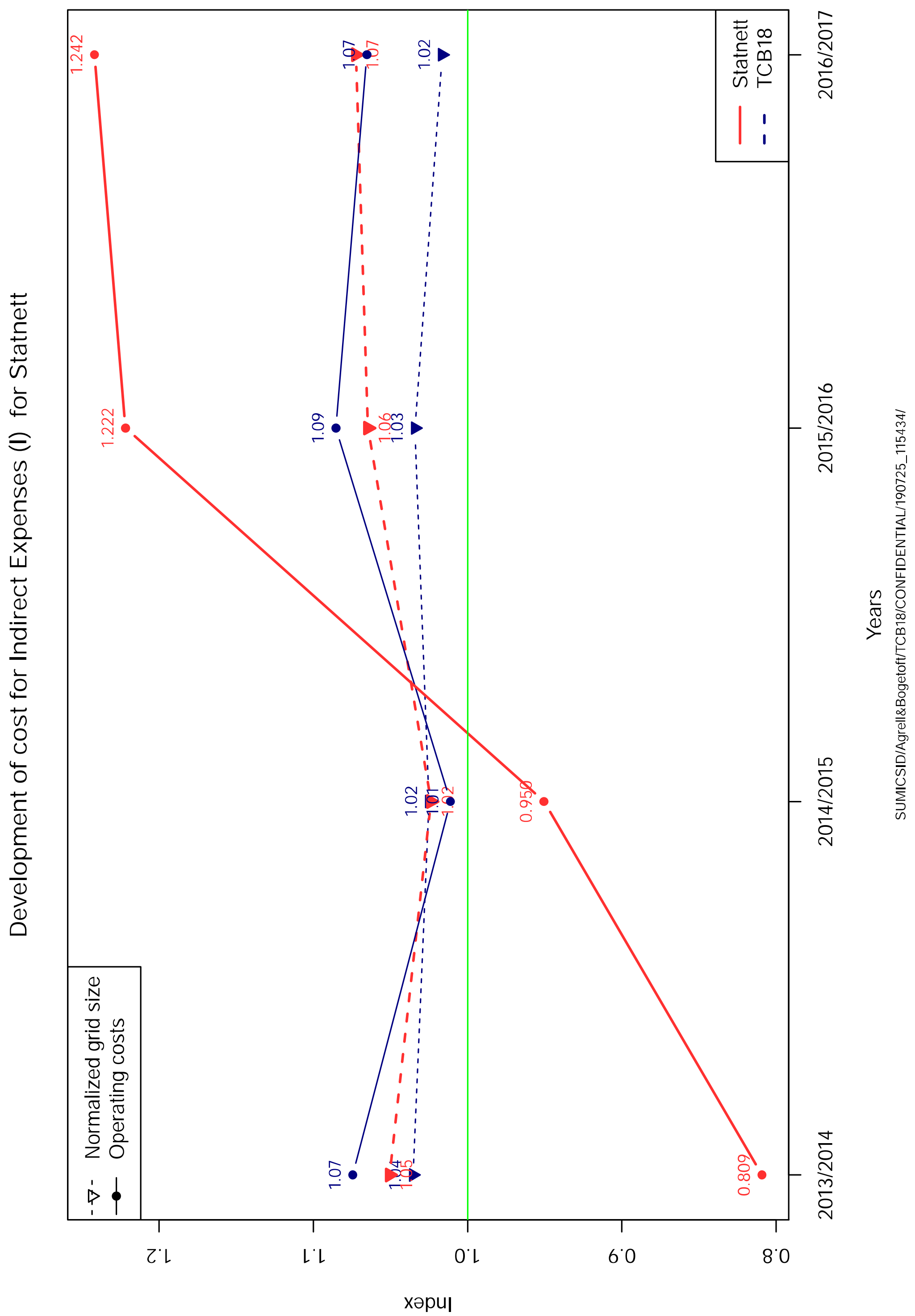

Figure 6.11: Cost development indirect support (I) vs grid growth.

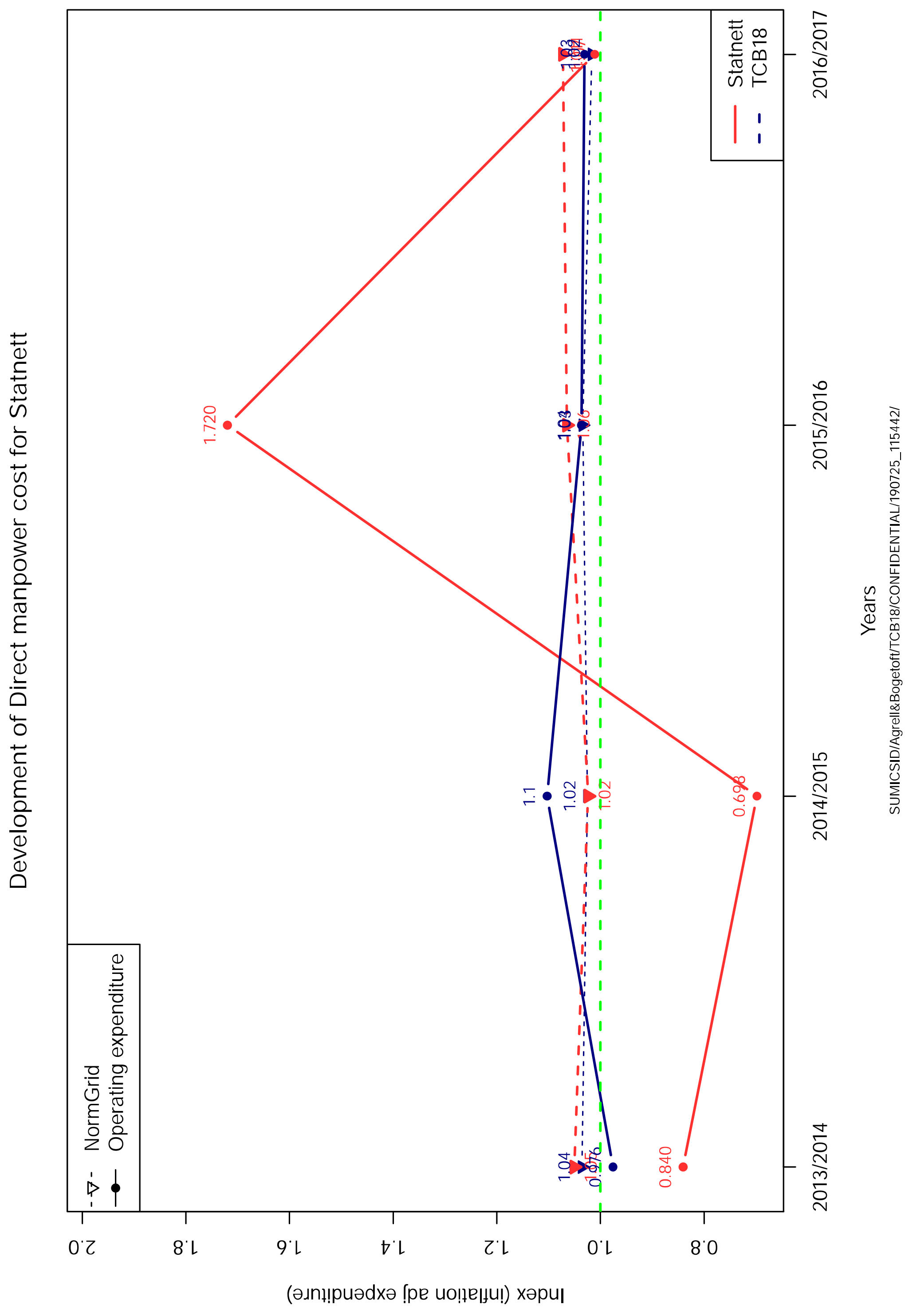

Figure 6.12: Cost development personnel expenditure (TMP)

Chapter 7

Parameters and index

The technical parameters in Table 7.1 and the indexes in Figures 7.1 and 7.2 are used in the calculations for the efficiency. The choice of these parameters is discussed further in the final report.

Table 7.1: Key parameters.

parameter.names	parameter.values
Template version	March 2018
Real interest rate	0.03
Exchange rate EUR 2017	0.107146190154701
Inflation index name:	hicpog_cpiw
Labor cost index name:	plici
Labor cost index 2017	1.508
Labor cost index 2016	1.485
Labor cost index 2015	1.483
Labor cost index 2014	1.558
Labor cost index 2013	1.625
Overhead allocation T	0.174
Overhead allocation M	0.242
Overhead allocation P	0.068
Overhead allocation S	0.186
Overhead allocation X	0.078
Overhead allocation TO	0.035
Overhead allocation SF	0
Overhead allocation O	0.218
Investment life lines	60
Investment life cables	50
Investment life substations	40
Investment life compdev	40
Investment life seriescomp	40
Investment life cc	20
Investment life other	20
Investment life equip	10

Table 7.2: Environmental variables.

parameter	datafile
dist_coast	tcb18_env_rugged_10.csv
near_coast	tcb18_env_rugged_10.csv
rugged	tcb18_env_rugged_10.csv
rugged_lsd	tcb18_env_rugged_10.csv
rugged_pc	tcb18_env_rugged_10.csv
rugged_popw	tcb18_env_rugged_10.csv
rugged_slope	tcb18_env_rugged_10.csv
wSubRegion	tcb18_env_area3_10.csv
yArea.arable	tcb18_env_area_10.csv
yArea.artifical	tcb18_env_area2_10.csv
yArea.bareland	tcb18_env_area2_10.csv
yArea.builtup	tcb18_env_area2_10.csv
yArea.coastalwetlands	tcb18_env_area2_10.csv
yArea.cropland	tcb18_env_area2_10.csv
yArea.forest	tcb18_env_area_10.csv
yArea.grassland	tcb18_env_area2_10.csv
yArea.greenhouses	tcb18_env_area2_10.csv
yArea.inlandwetlands	tcb18_env_area2_10.csv
yArea.land.tot	tcb18_env_area_10.csv
yArea.meadows	tcb18_env_area_10.csv
yArea.other	tcb18_env_area_10.csv
yArea.service	tcb18_env_areaservice_10.csv
yArea.shrubland	tcb18_env_area2_10.csv
yArea.tot	tcb18_env_area_10.csv
yArea.water	tcb18_env_area2_10.csv
yArea.wetland	tcb18_env_area2_10.csv
yArea.woodland	tcb18_env_area2_10.csv
yAreaShare.arable	tcb18_env_area_10.csv
yAreaShare.forest	tcb18_env_area_10.csv
yAreaShare.grass	tcb18_env_vegetation_10.csv
yAreaShare.meadows	tcb18_env_area_10.csv
yAreaShare.other	tcb18_env_area_10.csv
yAreaShare.shrubs	tcb18_env_vegetation_10.csv
yAreaShare.woods	tcb18_env_vegetation_10.csv
yClimate.heat	tcb18_env_climate_10.csv
yClimate.icing	tcb18_env_climate_10.csv
yLanduse.agriculture	tcb18_env_landuse_10.csv
yLanduse.industry	tcb18_env_landuse_10.csv
yLanduse.nonproductive	tcb18_env_landuse_10.csv
yLanduse.urban	tcb18_env_landuse_10.csv
yShare.area.agriculture_1	tcb18_env_area3_10.csv
yShare.area.agriculture_2	tcb18_env_area3_10.csv
yShare.area.agriculture_3	tcb18_env_area3_10.csv
yShare.area.agriculture_4	tcb18_env_area3_10.csv
yShare.area.cropland.tot	tcb18_env_area3_10.csv
yShare.area.forest_1	tcb18_env_area3_10.csv
yShare.area.forest_2	tcb18_env_area3_10.csv
yShare.area.forest_3	tcb18_env_area3_10.csv
yShare.area.grassland_1	tcb18_env_area3_10.csv
yShare.area.grassland_2	tcb18_env_area3_10.csv
yShare.area.grassland_3	tcb18_env_area3_10.csv
yShare.area.grassland.tot	tcb18_env_area3_10.csv
yShare.area.infrastructure_airport	tcb18_env_area3_10.csv
yShare.area.infrastructure_port	tcb18_env_area3_10.csv
yShare.area.infrastructure_roadrail	tcb18_env_area3_10.csv

yShare.area.infrastructure.tot	tcb18_env_area3_10.csv
yShare.area.noaccess_1	tcb18_env_area3_10.csv
yShare.area.noaccess_2	tcb18_env_area3_10.csv
yShare.area.otherw.tot	tcb18_env_area3_10.csv
yShare.area.shrubland.tot	tcb18_env_area3_10.csv
yShare.area.urban_1	tcb18_env_area3_10.csv
yShare.area.urban_2	tcb18_env_area3_10.csv
yShare.area.urban_ind	tcb18_env_area3_10.csv
yShare.area.urban.tot	tcb18_env_area3_10.csv
yShare.area.wasteland_1	tcb18_env_area3_10.csv
yShare.area.wasteland_2	tcb18_env_area3_10.csv
yShare.area.wasteland_3	tcb18_env_area3_10.csv
yShare.area.wasteland.tot	tcb18_env_area3_10.csv
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yShare.area.water_3	tcb18_env_area3_10.csv
yShare.area.water_4	tcb18_env_area3_10.csv
yShare.area.water_5	tcb18_env_area3_10.csv
yShare.area.wetland_1	tcb18_env_area3_10.csv
yShare.area.wetland_2	tcb18_env_area3_10.csv
yShare.area.wetland_3	tcb18_env_area3_10.csv
yShare.area.wetland_4	tcb18_env_area3_10.csv
yShare.area.wetland_5	tcb18_env_area3_10.csv
yShare.area.wetland.tot	tcb18_env_area3_10.csv
yShare.area.woodland.tot	tcb18_env_area3_10.csv
yShare.motorways	tcb18_env_roads_10.csv
yShare.other	tcb18_env_area3_10.csv
yShare.urbanroads	tcb18_env_roads_10.csv
zDensity.railways	tcb18_env_roads_10.csv
zDensity.roads	tcb18_env_roads_10.csv
zGravel_S_mean	tcb18_env_subsoil_10.csv
zGravel_S00	tcb18_env_subsoil_10.csv
zGravel_S05	tcb18_env_subsoil_10.csv
zGravel_S15	tcb18_env_subsoil_10.csv
zGravel_S40	tcb18_env_subsoil_10.csv
zGravel_S41	tcb18_env_subsoil_10.csv
zGravel_T_mean	tcb18_env_subsoil_10.csv
zGravel_T00	tcb18_env_subsoil_10.csv
zGravel_T05	tcb18_env_subsoil_10.csv
zGravel_T15	tcb18_env_subsoil_10.csv
zGravel_T40	tcb18_env_subsoil_10.csv
zGravel_T41	tcb18_env_subsoil_10.csv
zHumidity.wwpi	tcb18_env_wetness_10.csv
zLandhumidity.dry	tcb18_env_wetness_10.csv
zLandhumidity.water.perm	tcb18_env_wetness_10.csv
zLandhumidity.water.temp	tcb18_env_wetness_10.csv
zLandhumidity.wet.perm	tcb18_env_wetness_10.csv
zLandhumidity.wet.temp	tcb18_env_wetness_10.csv
zSlope.flat	tcb18_env_slope_10.csv
zSlope.hilly	tcb18_env_slope_10.csv
zSlope.mountain	tcb18_env_slope_10.csv
zSlope.undulating	tcb18_env_slope_10.csv
zSoil.dr_D	tcb18_env_subsoil_10.csv
zSoil.dr_M	tcb18_env_subsoil_10.csv
zSoil.dr_S	tcb18_env_subsoil_10.csv
zSoil.dr_V	tcb18_env_subsoil_10.csv

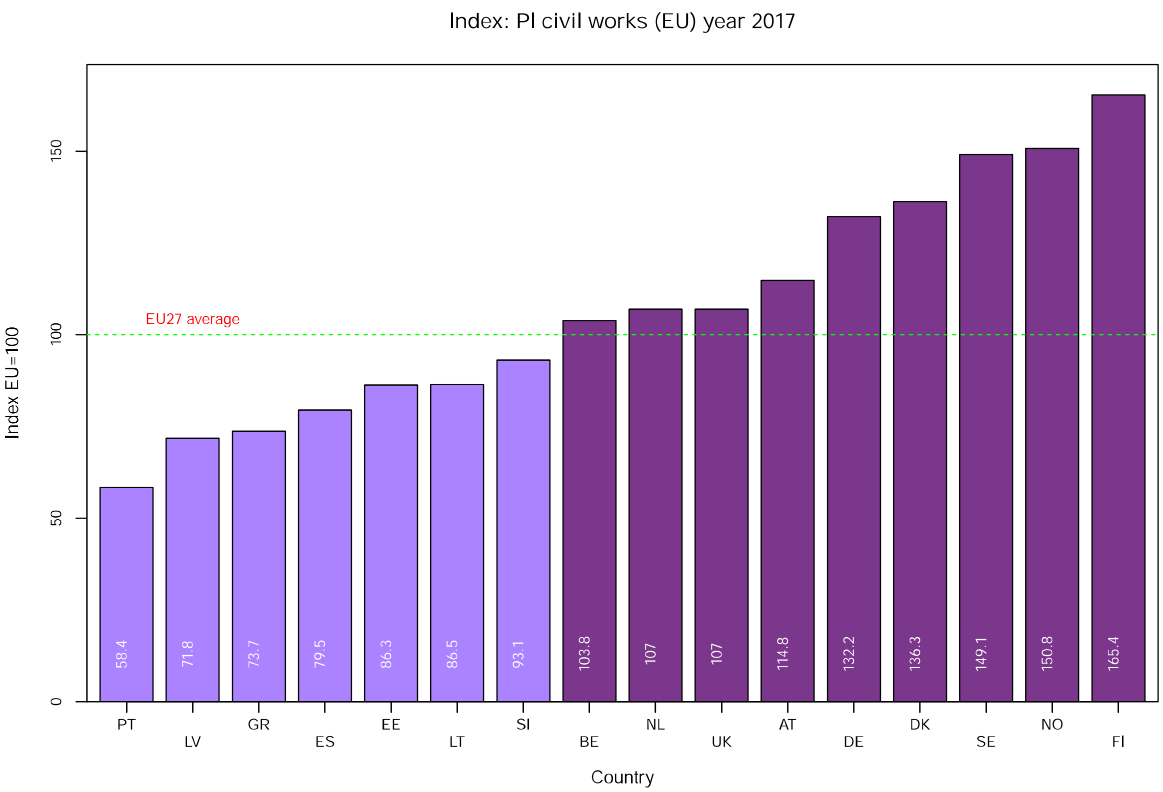


Figure 7.1: Labour cost index PLICI (EU civil engineering) by country 2017.

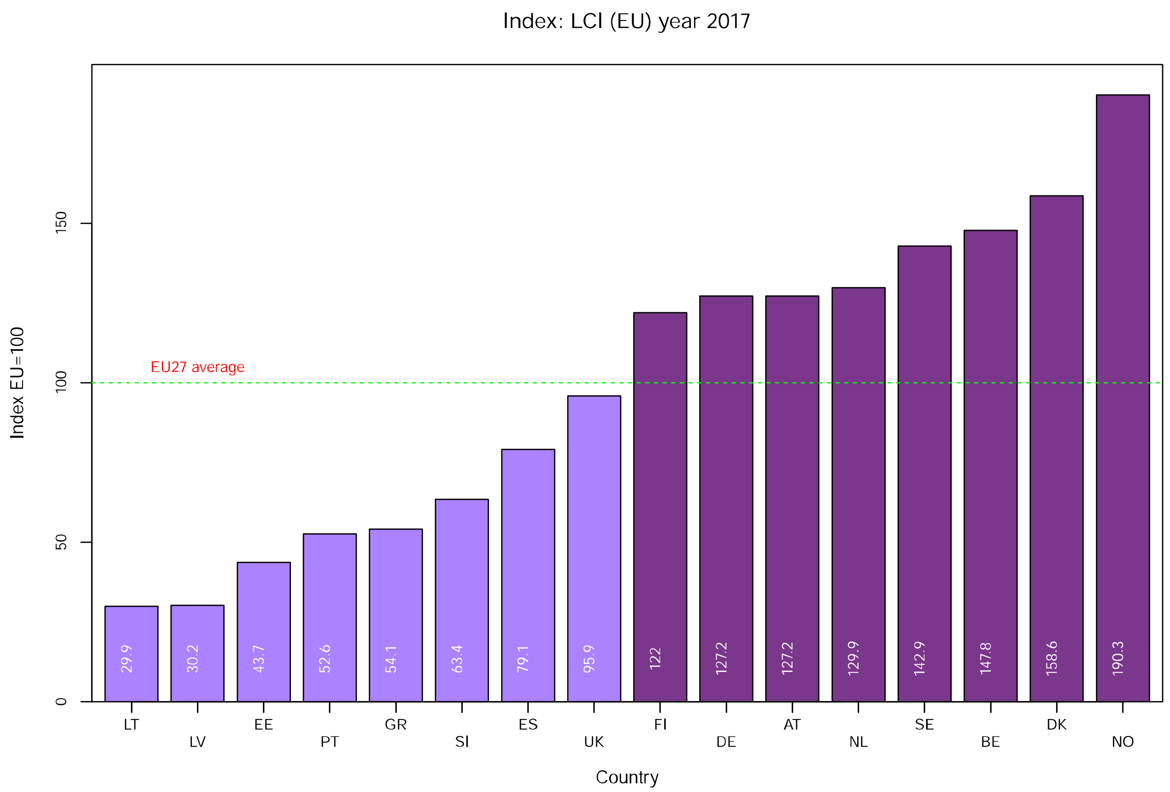


Figure 7.2: Labour cost index LCIS (EU general) by country 2017.

PROJECT CEER-TCB18

Pan-European cost-efficiency benchmark for electricity transmission system operators

APPENDIX

2019-07-17 V1.2

Appendix

A. Electricity asset reporting guide, 2018-03-08

CEER TSO Cost Efficiency Benchmark

Electricity asset reporting guide

Final version

8 March 2018

1. Introduction

1. The CEER benchmarking projects for electricity and gas Transmission System Operators (TSOs) use two data calls to collect the required data:
   1. the financial data call, and
   2. the asset data call.

2. For both calls TSOs report their data in a separate reporting template (Excel) based on separate reporting guides which are meant to explain how the templates have to be filled in. The current guide deals with the electricity asset call and goes with its associated asset reporting template. Basically the asset reporting presents a snapshot of the asset base at a specific date set by project management.

3. Note that this guide (and its associated reporting template) is essentially a further development of the asset reporting guide used in the previous CEER electricity TSO cost efficiency benchmark E3grid (2012-2013).

4. Please fill in all fields of the financial reporting template. To avoid misunderstandings, always fill in an explicit "0" or "N/A" if that is the case.

5. This guide is structured as follows. Chapter 2 of this guide describes the different asset categories that need to be reported. Chapter 3 provides general reporting directions. Chapter 4 contains specific instructions per asset category.

2. Network components (asset categories)

6. To describe the network (grid) several components (asset categories) that can be distinguished. In the reporting template there is a sheet for each asset category.

Transmission system

7. The transmission system is composed of different network layers characterized by their respective voltages. From interconnection level (380 and 400 kV in Europe), down to sub-transmission networks generally being part of the distribution system (in general using voltages under 100 kV). The boundaries between transmission and distribution activities can differ following the system that is considered. Some transmission systems are characterized by a single functional layer, like in the UK (made of 132kV, 275 or 400 kV). Other systems are made of two superimposed layers, in continental Europe these are often made of 380 and 225 kV networks. Transmission systems made of more than two layers also exist, e.g. the French system is made of at least three functional layers, most often 380, 225, and 90 or 63 kV.

8. By default, the installations are considered as being AC operated.

Layer composition

9. Each layer is composed of (and further characterized by):
    1. Substations
        a. Outdoor or indoor.
        b. Air insulated or metal clad (gas insulated, i.e. SF_6).
        c. Single, double or triple bus bars (possibly operated in sections connected via circuit breakers).
    2. Electrical circuits
        a. Overhead lines (single, double, triple, quadruple), all circuits not necessarily being operated at a same voltage level.
        b. Underground or underwater cables.
        c. DC connection (and their converters).
    3. Connections to other layers that are implemented using transformers or auto-transformers:
        a. Presenting 2 or 3 operational windings (connected or connectable to a grid).
        b. Equipped with tap changer:
        - In phase (for implementing voltage control).

- Or in quadrature[1] (phase shifter; for active power control).
- Or both in a compound device.

c. Tap changer operation:
- Off load
- Or on load (OLTC, On Load Tap Changer).

4. This is completed by specific AC devices:
a. Shunt compensation devices:
- Capacitive.
- Inductive.
- Or both in a single compound device.

b. Characterized by their control:
- Continuous (SVC, STATCOM, synchronous compensator).
- Mechanically switched (synchronously operated).
- Mechanically switched (non-synchronously operated).

c. Series components:
- Series inductance for short-circuit limiting.
- Series capacitors for increased transfer capacity (fixed, on-off, continuously variable).

5. Converter stations:
a. HVDC (line commutation).
b. HVDC (self commutated converters).

6. Control centers.

10. Conceptually systems are roughly developed following two distinct schemes:
1. A system based on the reactive compensation scheme. In that case the voltage control in the HV system is mainly implemented using HV reactive compensation.
2. An approach based on transformers with OLTC[2], assuring reactive power transfers between layers while decoupling layers voltages.

Systems exist where both approaches have been concurrently implemented.

Offshore grids

11. Offshore assets comprise:
1. Offshore transmission networks, i.e. all assets used to connect off shore wind farms (e.g. cables, platforms, converters), ending with and including the circuit end in the first (seen from the perspective of the off-shore wind farm) onshore AC substation, and

[1] Technologically, the series voltage is not necessarily based on a 90° phase shift ("quadrature" booster).

[2] On Load Tap Charger, sometimes also ULTC for Under Load Tap Changer.

2. Subsea interconnectors, i.e. subsea cables between (and including) two onshore (converter) stations from different countries that for a dominant part lie on the seabed or below it and is used to transport electricity from one country to another, e.g. the electricity interconnector between Norway and the Netherlands).

12. For the purpose of reporting, subsea cables that connect parts of the same network (i.e. intra-TSO) are not considered as offshore assets.

3. General reporting directions

Asset reporting

13. Assets are reported as they appear at a specific moment ("snapshot") defined by project management, see Article 2.

14. Offshore assets are excluded from reporting. Please note that according to Article 12, subsea cables that connect parts of the same network (i.e. intra-TSO) will be reported as cables (see Article 47) and indicated as submerged (ref. Articles 53 and 54).

15. Unless otherwise requested, the assets reported should relate to
    1. The reporting TSO's own assets that have not been decommissioned (i.e. those assets that are permanently not in use anymore by the TSO, no matter if these are removed or not) and that are partly or fully operated by the reporting TSO to fulfil its own supply obligations.
    2. Network components not owned by the reporting TSO, but leased, rented or otherwise made available (fully or partly) to the reporting TSO by third parties and used by the reporting TSO to fulfil its own supply obligations. For sake of asset reporting such components are considered as assets of the reporting TSO.

16. Assets which are owned by the reporting TSO, but not used by the reporting TSO to fulfil its own supply obligations because the assets are fully leased, rented or made available otherwise by the reporting TSO to third parties should be attributed to these third parties and should not be reported here.

17. With reference to Article 15, in case the asset is only used partly by the reporting, the share of usage must be reported. This share is based on capacities granted on a contractual basis and not on property or ownership shares. So, the reporting TSO has the asset to its free disposal for that part, regardless of the actual utilization. In such cases the name(s) of the parties with which the sharing is done will also be reported.

18. In the reporting transformers, circuit ends, compensating devices or series compensation reported must be related to a substation for validation purposes. In some countries, due to interests of national security, this information can only be available for the relevant NRA. If so, this will be ensured by the relevant NRA.

19. For the purpose of reporting towers and substations are not considered as primary assets, unlike all other assets to be reported. Towers and substations will be reported in order to better understand the complexity of the network.

Asset properties

20. Any asset reported must be given a unique ID, unless stated otherwise.

21. Reporting of all assets (except control centers) require information about nominal voltage. Unit of measurement is kV for all assets. The reporting will explicitly state the lowest represented voltage level and its prevalence in circuit km.

22. For circuit ends capacity in terms of breaking current must be reported (in kA). Deviations between nominal values and operational limits (e.g. due to climatic conditions) are neglected.

23. For lines, cables, transformers, compensating devices and series compensation nominal power in MVA must be reported. For transformers, the highest power value has to be considered, this is often the one of the higher voltage winding. For phase shifters the total of the series and shunt power values has to be reported.

24. In case of multiple circuits lines, each circuit must be considered separately. This permits to account for different operational voltages for circuits on the same tower.

25. A cable connection usually consists of multiple cables in a trench or a tunnel, where e.g. a trench can easily be 10 or more meters wide and different cables can be operated at different voltage levels. A cable connection consisting of a number of cables, all being operated at the same voltage level, is reported as a single asset. So, if the cable connection consists of cables operated at two different voltage levels, this is reported as two assets (two cable connections in the same corridor).

Commissioning, acquisition, and rehabilitation

26. The commissioning year of an asset is the year when the asset was put in operation (for the first time), irrespective of this was done by the TSO or a third party.

27. In case the asset has been obtained from a third party, in addition to the commissioning year, the acquisition year (year of investment, or at least the major part of it) also needs to be provided.

28. By default the commissioning year is equal to the acquisition year (in the template indicated as “N/A”).

29. In case the asset has been significantly rehabilitated the rehabilitation year also needs to be provided. Significant rehabilitation means a large incremental investment into an existing asset without change of any characteristics (i.e. its dimensions and properties). Large is defined as at least 25% of the (real) initial investment. Regular preventive and reactive maintenance, e.g. replacement of system components at or before their lifetime is not counted as a “rehabilitation”. Investments changing the characteristics are considered as “upgrades” and not as rehabilitation. The default reporting is “N/A”, i.e. there is no significant rehabilitation.

Generic data to be provided (per asset)

30. For each asset, the following information is asked for in the reporting template:

31. <u>ID:</u> See Article 20.

32. <u>Usage share:</u> A percentage, see Article 17. By default, full usage by the reporting TSO, 100% is filled in explicitly.

33. <u>Third parties:</u> These are the names of the parties the sharing is done with, see Article 17. By default “N/A” is reported to signal that no sharing is done (Usage share in Article 32 is 100%).

34. <u>Commissioning year:</u> See Articles 26 to 29.

35. <u>Acquisition year:</u> See Articles 26 to 29.

36. <u>Rehabilitation year:</u> See Articles 26 to 29.

37. Please refer to Chapter 4 for the required specific information per asset.

4. Specific reporting directions

38. Below, we introduce the data to be provided specifically for each asset.

Lines (Sheet "1. Lines")

39. An item in the overhead transmission line category is defined as a circuit, with a certain nominal current, operated at a certain voltage, installed on towers equipped with a certain number of circuits. Line specifics to report are the following:

40. Length: Length of the circuit (km).

41. Voltage: Nominal voltage (kV).

42. Power: Nominal power (MVA).

43. Number of circuits: Number of circuits per tower (1,2,3,…).

44. AC/DC: AC or DC.

45. Number of sub-conductor: Simplex (1), duplex (2) , or triplex (3).

46. Tower type: Dominant tower type (Wood, Steel, Concrete, Composite).

Cables (Sheet "2. Cables")

47. Definition of cables follow the same principles as lines, but lay underground or under water (submerged). Reporting is done at the level of cable connections, not at the level of individual cables that the connection consists of, see Art. 25 for a further explanation.

48. Offshore cables should not be reported here (see Article 11 for what is meant with offshore). Cable specifics to report are the following:

49. Length: Length of the circuit (km).

50. Voltage: Nominal voltage (kV).

51. Power: Nominal power (MVA).

52. AC/DC: AC or DC.

53. Usage: Land or Submerged. Submerged cables are defined as cables that lie at least 2 meters below the water surface for at least 1.000 meters and for at least 75% of their length.

54. Water crossed: In case the cable is submerged (Usage = Submerged), state the name of the water crossed (otherwise fill in N/A). This is the name as it is known to the public.

55. Number of cables: Number of cables the cable connection consists of (1,2,3,…), see Article 25.

56. Number of conductors: Number of conductors (1,2,3,…) per cable of the of connection. Usually this is 1 or 3. For high voltage cables this is usually 1. In case there are cables with different numbers of conductors, report the dominant type.

57. Insulation: PEX, XLPE, Oil, Gas filled, or Other.

Transformers (Sheet "3. Transformers")

58. All types of transformers playing a role in transmission shall be reported. Transformers supplying substations auxiliaries are excluded here from reporting as these are implicitly taken into account through circuit ends. Transformers of HVDC installations are included within the convertors and must also not be reported under transformers. Transformer specifics to report are the following:

59. Substation: ID of the substation the transformer is located in.

60. Primary: Primary voltage (kV).

61. Secondary: Secondary voltage (kV).

62. Tertiary: Tertiary voltage (kV), if applicable.

63. Power: Nominal power (MVA).

64. Number of transformers: Number of identical transformers in the relevant substation (1,2,3,…). Identical means that they have the same attribute values (voltages, Power, Type, Tap Changer, Phase Shift) and have the same commissioning year.

65. Type: Transformer type (Transformer, or Auto-transformer).

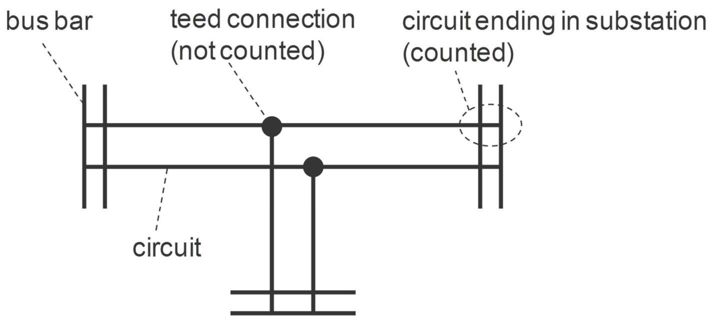
66. Tap Changer: Tap changer type (With or Without), i.e. with or without On Load Tap Changer (OLTC).

67. Phase shift: Phase shift yes/no (Yes or No).

Circuit ends (Sheet “4. Circuit ends”)

68. A circuit end is generally a bay in a substation. This applies to all types of devices connected in a substation (e.g. lines, cables, transformers, compensation devices, but also transverse couplers between bus bars, or longitudinal couplers between bus sections). For example, a UHV-HV two windings transformer has two circuit ends, one connected to the UHV bus and the other to the HV bus. “Auxiliary” devices such as earthing switches or measurement units shall not be counted here. Circuit end specifics to report are the following:

69. Circuit ends are only counted if the respective switchgear is owned by the TSO. Teed connections are not specifically taken into account in the present guide. Only the terminals ending in a substation will only be considered (see figure below). For the calculation of circuit length, the total length of the teed structure must be considered, at least when the type of the line is similar. Otherwise the different circuits must be sorted following the type of line. The circuit ends at the connection point on the line is considered as non-existent.



70. Circuit end specifics to report are the following:

71. Substation: ID of the substation the circuit end is located in.

72. Voltage: Nominal voltage (kV).

73. Current: Current breaking capacity (kA).

74. Number of circuit ends: Number of identical circuit ends (1,2,3,…) in the relevant substation. Identical means that they have the same attribute values

(Voltage, Current, Busbar, Coverage, Insulation) and have the same commissioning year.

75. Busbar: Single (1), double (2), triple (3), quadruple (4), Other.

76. Coverage: Outdoor (open air) or Indoor (in a building).

77. Insulation: Air insulated or Metal clad (gas insulated, i.e. SF_6).

Shunt compensating devices (Sheet "5. Compensating devices")

78. There are discrete (bank) and continuous compensating devices, for banks, single (fixed) and multiple steps (adjustable). For shunt reactor compensated lines, where inductance cannot be disconnected, compensating devices are considered as bank of fixed inductive compensation. Shunt compensating device specifics to report are the following:

79. Substation: ID of the substation the device is located in.

80. Voltage: Nominal voltage (kV).

81. Power: Nominal power (MVA).

82. Number of devices: Number of identical compensating devices (1,2,3,…) in the relevant substation. Identical means that they have the same attribute values (Voltage, Power, Type, Fixed or adjustable, Capacitive or inductive) and have the same commissioning year.

83. Type: Type of compensating device, i.e. Banks, SVC, STATCOM, or synchronous compensator (SynComp). See also Article 78 regarding reactors.

84. Fixed or adjustable: Single (Fixed) or multiple steps (Adjustable) for banks.

85. Capacitive or inductive: Capacitive (Cap), Inductive (Ind), or both (Both).

Series compensation (Sheet "6. Series compensations")

86. The series compensations are divided in two categories, inductive (for short-circuit current limiting) on one side and capacitive (for increased transfer capacity) on the other side. Inductive compensation is generally made of fixed components while capacitive series compensation can be made discretely or continuously adjustable. Series compensation specifics to report are the following:

87. Substation: ID of the substation the series compensation is located in.

88. Voltage: Nominal voltage (kV).

89. Power: Nominal power (MVA).

90. Number of devices: Number of identical series compensations (1,2,3,…) in the relevant substation. Identical means that they have the same attribute values (Voltage, Power, Control, Fixed or adjustable, Capacitive or inductive) and have the same commissioning year.

91. Control: (Discrete, or Continuous).

92. Fixed or adjustable: (Fixed, or Adjustable).

93. Capacitive or inductive: Series capacitors for increased transfer capacity, either discretely (CapDis) or continuously adjustable (CapCon), or series inductance (Ind) for short-circuit limiting.

Control centers (Sheet "7. Control centers")

94. Control centers in electricity transmission operations measure, regulate and control electricity flows from sources to consumers. ICT (hard- and software) used in a control centers is seen as integral part of it. This also includes grid related telecommunications (telecommunications solely related to the network). This comprises of transmission of electronic information for metering, control and supervision of the network with means other than through third-party operators. This also includes SCADA and optical fibers and other infrastructure that is used for telecommunication. For control centers the following is reported:

95. Name: Name of the control center.

96. Functions: A description of the main functions and characteristics of the control center.

97. Staffing: The control center is an operational unit that is staffed during normal operations (Yes) or an emergency (reserve or back-up) center that is fully equipped but not normally staffed (No).

Other installations (Sheet "8. Other")

98. FACTS or HVDC conversion stations are very specific installations. Their number worldwide is less than one hundred. Each constitutes a specific plant. To ensure a correct validation, converter stations are reported in a free format, specifying the adequate parameters. Use one line for each station without aggregation.

Other transmission installations of particular values may also be entered here. Specifics to report are the following:

99. Type: Type of installation (e.g. HVDC)

100. Characteristics: Further specification of the installation in terms of its main characteristics (e.g. voltage, capacity, power, etc.)

Towers (Sheet "9. Towers")

101. Reporting of towers differs from the other asset types in that they are not reported item by item but as a sum of identical asset, where identical refers to the attributes being reported. Tower specifics to report are the following:

102. Number: Number of identical towers (1,2,3,…), where identical means that they have the same reported attributes (Usage share, Third parties, Commissioning year, Acquisition year, Rehabilitation year, Voltage, Material, Type).

103. Voltage: Voltage level (kV). In case of towers for multiple circuits the highest voltage level applies (nominal, not operational).

104. Material: Main material the tower is composed of (Wood, Steel, Concrete, Composite, or Other).

105. Type: Type of tower (Suspension, or Angular).

Substations (Sheet "10. Substations")

106. An item in the substation category is generally defined as a grid connection point with transformers, switches, compensating devices or series compensation. Substation specifics to report are the following:

107. Voltage: Highest nominal voltage (kV) in the substation. This is the nominal voltage on the primary side of the highest voltage transformer within the substation. This is also referred to as rated voltage.

108. Type: Transformer, Switching, or Other.

B. Financial reporting guide, 2018-03-08

CEER TSO Cost Efficiency Benchmark

Financial reporting guide

Final version
8 March 2018

1. Introduction

1. The CEER benchmarking projects for electricity and gas Transmission System Operators (TSOs) use two data calls to collect the required data:
   1. the financial data call, and
   2. the asset data call.

2. The financial reporting templates (Excel) and this associated financial reporting guide constitute the financial data call. The reporting of assets is defined in the asset data call.

3. TSOs report their data in the financial reporting template. There are separate templates for electricity and gas. This guide is valid for both electricity and gas and is meant to explain how the reporting template(s) has/have to be filled in.

4. Note that this guide (and its associated reporting template) is essentially a further development of the financial reporting guide used in the previous CEER electricity TSO cost efficiency benchmarks E3grid (2012-2013) and E2gas (2015/2016).

5. TSOs report their data based upon their audited financial statements[1]. This way the costs reported in the investment stream align with the costs of investments in the audited financial statements and the reported expenses align with the expenses in the profit and loss account of the audited financial statements.

6. Although it is important that total investments and expenses match the audited financial statements, it might be possible that the required breakdown of costs and expenses does not match your audited financial statements. In that case it is acceptable if you use your general ledger and project administration in order to make estimates as good as possible. Please provide clarification if you have made estimates.

7. Regarding assets owned by the group to which the TSO belongs, but not by the TSO itself, the relevant investment data of the group company have to be used.

[1] This means that only financial accounting data has to be reported. Regulatory (accounting) data shall not be reported.

8. In case TSOs do not publish their audited financial statements, the reported investments and expenses should be visible in the segmented financial information of audited consolidated financial statements of the parent company.

9. TSOs report their data for a given year in the currency used in the audited financial statements of that year.

10. Please note that not all reported investments and expenses will be in scope of the benchmark study, but that some elements are required only for verification purposes.

11. The International Financial Reporting Standards (IFRS) have been used as the basis for this guide, although this does not exclude the possibility that some TSOs use other accounting systems.

12. Please fill in all fields of the financial reporting template. To avoid misunderstandings, always fill in an explicit “0” or “N/A” if that is the case.

13. This guide is structured as follows. In Chapter 2, the activities of TSOs in which the financial reporting is decomposed are described. Chapter 3 of this guide deals with investment reporting. Chapter 4 describes the expense reporting.

2. Activities

Definitions

14. This financial guide uses definitions in accordance with the glossaries of ENTSO-E[2] and ENTSOG[3] where possible. Main definitions can be found per chapter. The appendix contains other definitions.

15. The various asset categories for the transport activity are defined in the asset guide.

Activities

16. When reporting investments and expenses, a distinction is made between different activities:
    T Transport;
    M Grid maintenance;
    P Grid planning;
    S System operations;
    X Market facilitation;
    TO Offshore;
    SF Storage Facility;
    L LNG facility (gas only); and
    O Any other activity;
    I Indirect expenses.
    Note that I is not a real activity, but for the reporting dealt with as such.

17. Four elements of expenses are, for the amounts reported in the profit and loss account of the audited financial statements, excluded from allocation to activities:
    a) depreciation, impairment and amortization of assets (excluding depreciation of equipment and vehicles and non-grid related telecommunications);
    b) finance income and expenses (interest); and
    c) taxes on declared annual profits
    d) extraordinary expense and income[4].
    These elements are reported on a separate sheet of the reporting template.

[2] https://www.entsoe.eu/data/data-portal/glossary/Pages/home.aspx

[3] https://www.entsog.eu/publications/glossary-of-definitions#GLOSSARY-OF-DEFINITIONS

[4] IFRS prohibits reporting expenses and income as extraordinary, other accounting systems however may still be allowing this.

18. Main changes in comparison to previous CEER TSO cost efficiency benchmarks (E3Grid in 2012/2013 and E2Gas in 2015/2016) are:
    - The term 'function' in E3Grid was changed into 'activity' in E2Gas. This financial guide uses the term 'activity'.
    - The A activity was renamed into the I activity to represent all indirect costs and expenses.
    - E2Gas introduced the T activity, which is now common to both electricity and gas.
    - The construction activity (C) has been removed since almost all activities of construction are capitalized and the activity appeared to have no assets or expenses in the audited financial statements of TSOs.
    - The grid ownership activity (F) has been removed since finance income and expenses are omitted from allocation to activities.
    - TO is included in order to have a more refined understanding of the grid.

T Transport

19. For investments (CAPEX) this activity includes all costs regarding construction and maintaining the network[5], excluding offshore.

20. For expenses (OPEX) this activity includes the expenses for metering, the purchase of energy for operating the network[6], grid-related insurance and day-to-day management of the network functionality.

21. For revenues this activity includes revenues from third parties for assets used by these parties with a usage share higher dan 0% and lower than 100%[7], reported in the audited financial statements as revenues.

M Grid maintenance

22. For investments (CAPEX) the maintenance is included in the T activity.

23. For expenses (OPEX) this activity includes all expenses regarding maintaining the network.

P Grid planning

24. For investments (CAPEX) this activity includes planning costs which are capitalized as a part of the investment stream[8]. These planning costs are

[5] This includes grid-related equipment and vehicles which are not specified in the asset reporting.

[6] Mainly purchase of energy for network losses.

[7] Costs and expenses of assets with a usage share of 0% are reported under O (Other activities). Assets with a usage share of 100% do not have revenues from third parties.

the costs associated with receiving the permit to construct (a part of) the transmission system and includes costs for environmental studies.

25. For expenses (OPEX) this activity includes all expenses regarding the analysis, planning and drafting of network expansion and network resources, including the expenses for the ten-year network development plan and non-capitalized research and development. This includes long-term planning.

S System operations

For electricity only

26. For expenses (OPEX) this activity includes all expenses regarding balancing services, primary and secondary reserves, capacity management, ancillary services (disturbance reserves, voltage support) and the purchase of energy for congestion management and redispatching. This activity excludes day-to-day management of the network functionality.

For gas only

27. For expenses (OPEX) this activity includes all expenses regarding ancillary services and congestion management. This activity excludes day-to-day management of the network functionality.

X Market facilitation

28. For expenses (OPEX) this activity includes all direct involvement in energy exchanges through information provision or contractual relationships. This comprises regulated tasks through procurement or renewable power, residual buyer obligations or capacity allocation mechanisms, capacity auctioning mechanisms, and work on coordination of feed-in tariffs. This activity includes direct expenses related to the contractual relations excluding transport and storage, primarily information expenses and energy purchases for other purposes than the consumption in the network of the TSO.

29. For revenues this activity includes pass-through income regarding market facilitation, reported in the audited financial statements as revenues .

TO Offshore

30. This activity is defined like T, but for offshore only.

[8] These only need to be reported for the most recent five years

SF Storage facility

31. All direct and indirect costs and expenses of (gas) storage facilities and peak-shaving plants.

L LNG Facility (gas only)

32. All direct and indirect costs and expenses associated with LNG facilities.

O Other activities

33. This includes all costs and expenses for activities that are not covered by any other activity, for example:
    a. costs and expenses for all assets which are owned by the reporting TSO, but not used by the reporting TSO to fulfil its own supply obligations because the assets are *fully* (100%) leased, rented or made available otherwise by the reporting TSO to third parties. Note that none of these assets should be reported in the asset reporting;
    b. personnel on the payroll of the TSO and working for a group company.

I Indirect expenses[9]

34. For expenses (OPEX): expenses (e.g. personnel) for administrative support, non-grid related insurance, non-grid related telecommunications, non-grid related equipment, non-grid related vehicles, management, and expenses for the main office. This activity does not include research & development, grid related telecommunications, grid-related insurance and grid-related equipment and vehicles.

[9] Indirect expenses have to be accounted for separately in the OPEX sheet only. A TSO may have indirect cost allocated to CAPEX, but specification of that is not asked for. In contrast to all other activities, which are direct activities, the indirect activity is not an actual activity but for the reporting will be dealt with as such.

3. Investment reporting

Main definitions

35. Investments are expenditures for assets (or components thereof[10]) that are recognized in the audited financial statements as tangible fixed assets.

36. Investments in used assets are expenditures for second-hand assets which were previously owned by a different company (not being a group company), e.g. a DSO or another TSO. Contrary to investments in new assets the acquisition year will differ from the commissioning year. The opening balance assets for a new TSO is also an investment in used assets.

37. Significant rehabilitation investments are large incremental investments into an existing asset without change of any characteristics (i.e. its dimensions and properties). Large is defined as at least 25% of the (real) initial investment. Regular preventive and reactive maintenance, e.g. replacement of system components at or before their lifetime is not counted as a "rehabilitation".

38. Upgrades are investments in existing assets changing the characteristics. Upgrades should be reported as investments.

39. Acquisition year is the year assets are recognized in the audited financial statements.

40. Commissioning year is the year assets, when they are new, are put into operation.

41. Disinvestments are disposals of assets (or components thereof) that are derecognized in the audited financial statements.

42. Capitalized borrowing costs are defined in International Accounting Standard 23, *Borrowing costs*.

43. Capitalized land are the costs of the investments that are due to purchase of land and capitalized payments to third parties as a result of a legal process (e.g. expropriation or compensation agreement), procurement or negotiation, related to the damage, injury of land, and /or the right to use land, roads or waterways for the activities of the TSO. This includes the capitalized direct expenses for judicial assistance, court fees etc. for legal

[10] Including fences, security cameras, etc.

processes (terminated or non-terminated) related to the use, damage or injury of land for the activities of the TSO.

44. Capitalized planning costs are the costs of the investments that are due to planning.

45. Gross investment stream is defined as investments per calendar year over time.

46. Disinvestment stream book year is defined as the original cost[11] of disinvestments per year, as occurred in the book year, over time.

47. Disinvestment stream acquisitioning year is defined as the original cost of disinvestments per year, as occurred in the acquisition year, over time.

48. Investment contributions are defined as payments by third parties for investments, investment grants and subsidies received.

49. Net investment stream is defined as the gross investment stream minus the disinvestment stream acquisitioning year.

50. Asset categories are identifiable groupings of assets. The definitions of the asset categories within the T, M and P activities can be found in the asset guides, with the exception of the asset category 'grid-related equipment and vehicles' (see the appendix for the definition). For the financial reporting the following asset categories are combined:
    - Lines and towers (electricity only)
    - Substations, transformers and circuit ends (electricity only)

51. Cost is defined in International Accounting Standard 16, *property, plant and equipment.*

52. Capitalization threshold is the amount above which assets are recognized in the audited financial statements.

53. Major spare parts, stand-by equipment and servicing equipment are defined in International Accounting Standard 16, *property, plant and equipment.*

[11] Ref. article 60

Investment stream and disinvestment stream

54. Investments are reported in the investment stream in the year the underlying assets are put *into* operation.

55. Disinvestments are reported both in the year they occurred and also in the acquisition year. The sum of all disinvestments in the disinvestment stream book year has to be equal to the sum of all disinvestments in the disinvestment stream acquisitioning year[12].

56. The investments in the investment stream for a given year should correspond to the investments in tangible fixed assets in the audited financial statements of the TSO for that year.

57. The disinvestment stream book year should correspond to the disinvestments as reported in the audited financial statements of the TSO for that year.

58. Investments are reported at cost[13] and have to be based on evidence, e.g. invoices.

59. Investment contributions[14] have to be reported separately.

60. Disinvestments are reported at the original cost of the corresponding investment and have to be based on evidence, e.g. invoices.

61. (Dis)investments are reported in asset categories as specified in chapter 2 of this guide (Activities).

62. The investment stream data for asset categories in activity T should correspond to the assets reported in the asset data call.

63. Major spare parts, stand-by equipment and servicing equipment are included in the investment stream only if they are recognized as tangible fixed assets in the audited financial statements of the TSO.

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[12] For example: a disinvestment in 2017, regarding an asset acquired in 2000 for €100.000, has to be reported in the year 2000 in disinvestment stream acquisitioning year at €100.000 and the year 2017 in disinvestment stream book year at €100.000.

[13] Revaluations or write-ups are not taken into account.

[14] Depending on the accounting methods in the audited financial statements an investment of € 100 million with an investment contribution of €10 million was reported at €100 million or €90 million. The TSO has to report which of the two methods was used.

64. Investments in significant rehabilitations are reported both in the (dis)investmentstream and separately. TSOs report the ID of the rehabilitated asset (as reported in the asset reporting), asset category, commissioning year, rehabilitation year and the rehabilitation investment amount.

65. Investments in used assets are reported both in the (dis)investmentstream and separately. The remaining weighted average[15] technical lifetime of these assets as estimated by the TSO is reported as well.

66. Figure 1 below shows a flowchart of how to deal with monetary items spent on assets in terms of this reporting.

Gas only

67. Some specific asset categories are reported both in the (dis)investmentstream and separately. These asset categories are inshore pipes, odorization assets, gas chromatographs, and integrated delivery stations (including the reported assets it comprises, like regulators).

[15] Weighted average is necessary when a TSO acquires multiple used assets in one year, with different remaining lifetimes per asset.

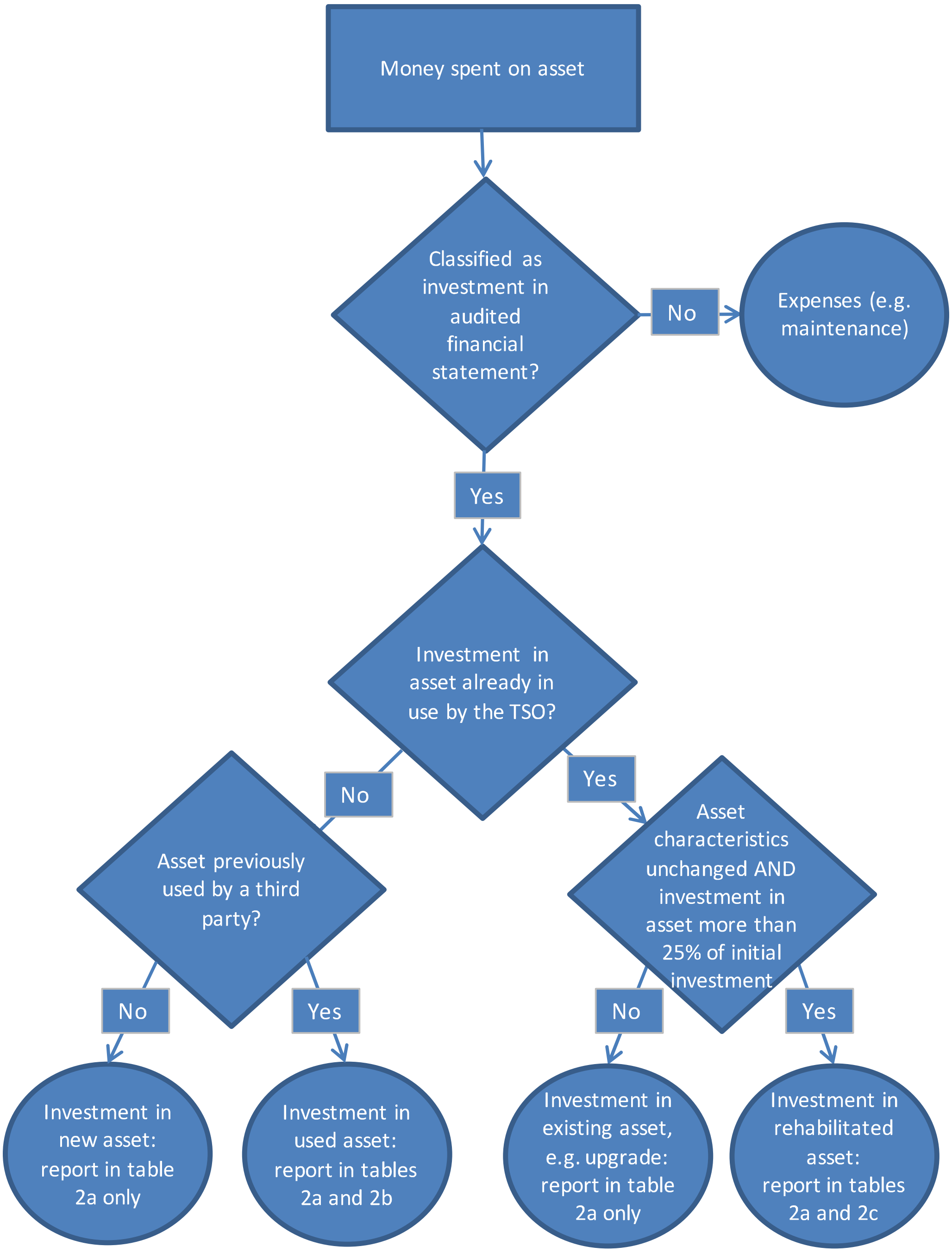

Figure 1: Flowchart for treating investments in this reporting

4. Expense reporting

Main definitions

68. Personnel expenses are the non-capitalized expenses for internal and external personnel including all taxes, charges or fees related to salaries, pensions and other payroll items. This includes personnel on the payroll of the TSO, personnel on the payroll of a group company and carrying out activities for the TSO and hours of temporary personnel carrying out activities for the TSO.

69. Energy expenses are the non-capitalized expenses for purchasing gas and/or electricity to operate machinery and buildings, for energy losses during transport, and for congestion management and redispatch.

70. Expenses for landowner compensation, right-of-way and easement fees are the non-capitalized payments to third parties as a result of a legal process (e.g. expropriation or compensation agreement), procurement or negotiation, related to the damage, injury of land, and /or the right to use land, roads or waterways for the activities of the TSO. This includes the direct expenses 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.

71. Expenses for taxes and levies are non-capitalized state, municipal and regional taxes, levies and public fees paid for the ownership of specific assets (e.g. property taxes, packaging), the 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).

Expense reporting[16]

72. The total expenses reported for a given year should be equal to the expenses in the audited financial statements of the TSO for that year, excluded the expense elements as in Article 17 of this guide.

73. The TSO specifies cost elements per activity as required in the template.

74. The TSO clarifies, per activity, on other expenses.

[16] Any revenue classified in the profit & loss account in the audited financial statements as revenue should not be reported in table 3 (expenses) of the financial reporting template but in table 4 (P&L) only.

Appendix - glossary

Ancillary services
All services necessary for access to and the operation of transmission networks, distribution networks, LNG facilities, and/or storage facilities, including load balancing, blending and injection of inert gases, but not including facilities reserved exclusively for transmission system operators carrying out their functions (source: ENTSOG glossary).

CAPEX
Capital expenditure

Control center
See asset guides for the definition.

Control center expenses
The profit & loss items associated with control centers.

Day-to-day management
The activity to ensure the daily operational availability of the network, including personnel safety (instructions, training), equipment security including relay protection, operation security, cyber security, coordination with operations management of the interconnected grids, coupling and decoupling in the network and allowances to personnel/contractors acting on the live grid. This includes staffing of the control centers.

Energy expense
The profit & loss item for energy.

Expense for landowner compensation, right-of-way and easement fees;
The profit & loss item for landowner compensation, right-of-way and easement fees.

Expense for odorization
The profit &loss item for odorization.

Expense for rent/lease of main office building
The profit &loss item for the main office of the TSO.

Expense for taxes and levies;
The profit & loss item for taxes and levies.

Full-time equivalent
The number of employees on full-time schedules plus the number of employees on part-time schedules converted to a full-time basis.

Grid maintenance
The activity preserving an asset's operational status without extending its life.

Grid planning
The activity concerning planning the development of a network including individual assets.

Grid-related equipment and vehicles
Auxiliary items meant to ensure the functioning of the grid, including vehicles meant for equipment and spare-parts.

Grid-related insurance
Insurance premiums covering the network.

Grid-related telecommunications
See asset guides for the definition.
Investments in grid-related telecommunications have to be reported under the asset category ‘control centers’.

Inshore water crossing
See asset guides for the definition.

Integrated delivery station (gas only)
In case the connection point has a delivery station, there can be two situations. Either the delivery station is not an integrated part of the TSO’s network, i.e. the connection point lies directly behind a safety valve, or the delivery station is an integrated part of the TSO’s network, i.e. the connection point lies behind the delivery station (Integrated). The latter type of delivery station is referred to as an integrated delivery station.

LNG facility (gas only)
A terminal which is used for the liquefaction of natural gas or the importation, offloading, and re-gasification of LNG, and includes ancillary services and temporary storage necessary for the re-gasification process and subsequent delivery to the transmission system, but does not include any part of LNG terminals used for storage (source: ENTSOG glossary).

Long-term planning (electricity only)
The planning of the need for investment in generation and transmission and distribution capacity on a long-term basis, with a view to meeting the demand of the system for electricity and securing supplies to customers (source: ENTSO-E glossary).

Long-term planning (gas only)
The planning of supply and transport capacity of natural gas undertakings on a long-term basis with a view to meeting the demand for natural gas of the system, diversification of sources and securing supplies to customers (source: ENTSOG glossary).

Main office
The main office of the TSO (expenditure for renting/leasing the building and the underlying land).

Main office expenses
Non-capitalized expenses for renting or leasing the main office and the underlying land.

Non-grid related insurance
Insurance premiums not related to the network.

Non-grid related telecommunications
Telecommunication cost and expenses not related to the grid. This includes telecommunications for third parties for (e.g. optical fiber or mobile infrastructure) and associated costs, income and expenses which have to be reported under the activity O.

Offshore
See asset guides for the definition.

OPEX
Operational expenditure

Other expenses.
Expenses not attributable to any other expense item.

Pass-through
Monetary item for market facilitation in which expenditure equals income.

Personnel expense
Expenses for internal and external personnel, both on payroll and temporary.

Research & development
Innovative activities in developing new services or products, or improving existing services or products.

Revenue
The profit & loss items reported in the financial statements as revenue.

Storage facility (electricity only)
A facility used to capture energy produced at one time for use as electricity at a later time.

Storage facility (gas only)
A facility used for the stocking of natural gas and owned and / or operated by a natural gas undertaking, including the part of LNG facilities used for storage but excluding the portion used for production operations, and excluding facilities reserved exclusively for transmission system operators in carrying out their functions (source: ENTSOG glossary).

System operations (electricity)
Activities regarding balancing services, primary and secondary reserves, capacity management and ancillary services (disturbance reserves, voltage support).

System operations (gas)
Ancillary services and congestion management.

Transport
The transport of electricity or gas on the network with a view to its delivery to final customers or to distributors.

Usage share
See asset guides for the definition.

C. Special conditions reporting guide, 2018-09-13

CEER TSO Cost Efficiency Benchmark

Special conditions reporting guide

FINAL VERSION

13 September 2018

1. Introduction

1. This reporting guide belongs to the CEER benchmarking project and is meant to give TSOs an opportunity to signal conditions that are not taken into account by the benchmark model, but should have been. Such conditions are referred to as special conditions and may call for correction of benchmarked scope or data, or the benchmark model. The concept of special conditions evolves from the concept of so-called Z-factors in previous CEER benchmarks.

2. Defining and implementing special conditions is meant to get closer to the purpose of the benchmark, i.e. to define best practices. As all TSOs in the sample will be related to frontier companies, it is therefore important that special conditions should only be labelled as such if they stand a number of criteria. We explain these in Chapter 2.

3. Special conditions can be claimed by TSOs in a process that starts once the draft benchmark model has been presented. In Chapter 3 we describe the procedure for this.

4. The criteria set in Chapter 2 are cumulative, forming a firewall to improper claims in order to protect the hygiene of the best practice frontier, which is in the interest of all TSOs. Individual interests can only impact the benchmark if this is reasonable to all. This is why the criteria will be evaluated critically and why transparancy of claims is necessary.

5. Nevertheless, as the benchmark can be used in regulation, individual interests are of course quite relevant, think of a severe unfortunate incident in the reference year, strong political pressure on the TSO, legacy, or regulatory decisions. However, such cases boil down to interpretation of an individual benchmark score, which is a national affair between individual NRAs and TSOs, just like with implementation of benchmark results afterwards in regulatory decisions. So it is important to bear in mind that there is a cut-off point where international benchmarking stops and national interpretation and implementation starts. The benchmark model defines that point and the criteria for special conditions are instrumental to that. Note that by accepting or denying claims, CEER does not mean to interfere in national discussions, let alone regulatory decisions. CEER's only intention here is to set a proper best practice frontier.

6. Note that most claims made in previous benchmarks for so-called Z-factors that were accepted have been implemented in the data definition guides for the current benchmark and will probably be included in the current benchmark

model. Therefore, for these claims there may be little point in re-claiming these as special condition again, unless of course the current benchmark model fails to include these Z-factors adequately.

7. Claims that were denied as Z-factors in previous benchmarks can be re-claimed. However, validation of re-claims will strongly focus on new relevant information, where having a very different sample of TSOs can be new relevant information too, and will probably be relatively brief. Hence, without substantial new information, the outcome will probably be negative again.

8. Finally, in previous benchmarks a relatively small portion of claims was accepted as Z-factor. Given the above and ceteris paribus, CEER does not expect many special conditions reported or accepted in the current benchmark. Also, claiming many special conditions does not make a credible case. However, CEER does not want to rule out that special conditions exist. Hence the current procedure for claiming and validating special conditions.

2. Special conditions

9. Below we explain the (cumulative) criteria for special conditions, without suggesting an order of importance.

Complementarity

10. This criterion is meant to distinct conditions that are already sufficiently dealt with by the benchmark model from conditions that are not and may need complementary treatment. For example, if the condition can be dealt with by building additional standard assets, and if the model would "credit" TSOs for their asset base, then the condition is likely to be already taken into account sufficiently by the model.

11. Note that there can be two reasons for complementary treatment. First of all, this could be the case if the benchmark model is insufficiently specified. A typical example of complementary treatment in such case would be the change or addition of a modelling parameter. Secondly, complementary treatment may be called for if the claimed condition is something very specific that only one or few TSOs in the sample have to live with, i.e. the condition is relatively unique to the claimant.

12. With reference to Article 5, complementary treatment implies that reporting/acceptance of the condition as special fits the purpose of the benchmark.

Objectification

13. A special condition is something that, so to say, overcomes a TSO, i.e. it can reasonably not be held against the TSO and this should not be arguable.

14. Special conditions must not be defined in terms of the (subjective) strategy to deal with the condition. So a claim cannot be formulated like "we do A because of condition C", because A would only refer to a choice made by the TSO that may be up for efficiency analysis. Instead a claim should be formatted like "we are faced with condition C and dealing with it inevitably comes with a disadvantage (compared to not having C)." So, both the condition C and the unavoidability of a disadvantage must fully and inarguably be beyond control of the TSO.

15. Objectivity also implies that the condition is conceptually simple, obvious, and transparent, even to less informed public. The rationale for this is that the more reasoning is needed to explain the condition, the more subjective, hence arguable, arguments it will be based on. Note that transparency includes the

vision that it must be clear to all parties which TSO is claiming what, without of course violating data confidentiality.

Durability

16. Incidents do not qualify as special conditions, think e.g. of a flooding in a certain year. Instead, special conditions are supposed either to exist over a substantial part of the reporting period, i.e. many years, or to exist for many years in the future impacting operations in the past. There is no explicit norm for this as it may depend on the precise nature of the condition (geographical, technical, economical, etc.). At any rate, this criterion is meant to separate structural circumstances from incidents.

Materiality

17. Special conditions can only be recognized as such if they come with a well-defined and significant cost impact. Below we elaborate on this.

18. The cost impact of a special condition is defined as the minimum unavoidable cost to deal with the condition. This is what is seen as the value of the claim. Put differently, the value of the claim is the cost difference between the lowest cost alternative to deal with the condition (this is not per se the alternative that is actually implemented) and the cost that would have been made if the condition would not exist. The value of the claim may be an estimate as it is at least partly based on counter factual information. Note that the value of the claim can be zero if there is an alternative to deal with the condition without additional cost (claims of that kind do not have to be reported.)

19. Hence, the cost impact of a special condition must be clearly quantifiable. If quantification is ambiguous or poorly documented, it will be difficult to correct in the benchmark for the condition. Moreover, it would signal that the condition does not have (had) the explicit attention of management as such, which makes the condition being a special one less credible.

20. Also, the (monetary) value of the claim must be significant, i.e. it must be big enough to significantly impact the outcome of the benchmark. A soft norm for this is about 5 percent of the benchmarked gross investment stream of the claimant or, if the claim is about expenses only, about 5 percent of its benchmarked expenses. With “benchmarked” we refer to the activities in scope of the (draft) benchmark. Significance is important to avoid erosion of the best practice frontier by relatively small peculiarities of which all TSOs will have some, some fortunately, some unfortunately.

3. Guidelines for submitting claims

21. Any TSO that, after having taken notice of this guide and the draft benchmark model, believes or suspects that the model does not take some condition (properly) into account, can make this clear by submitting a claim for a special condition.

22. With draft benchmark model we refer to the following elements:
    a) Scope of the benchmark model.
    b) Selected output parameter candidates.
    c) Control parameters, like the rate of return, scaling assumptions, indexations, or environmental factors.

23. A claim will be taken into consideration if it contains the following information:
    a) A brief description of the condition, ref. Article 14.
    b) Whether or not the claim has been claimed before in a Z-factor process and if so, why the claimant thinks he has substantial new information, ref Article 7.
    c) A motivation why the condition should lead to complementary treatment by the benchmark model, ref. Articles 10-12.
    d) A motivation why and how the condition is objectifiable, ref. Articles 13-15.
    e) A motivation why the condition is structural, ref. Article 16.
    f) A motivation why the condition is material, ref. Articles 17-20.

24. There is no template document for a claim, but the format of it should be consistent with Article 23. Motivations and quantification include all relevant documentation and/or other evidence.

25. A claim can be submitted by uploading the following documents to the private TSO folder of the project platform:
    a) The information under Article 23, items a-e, put together in a single document that is readily publishable to other TSOs and NRAs.
    b) Any supporting material, to which reference is made in the document meant under (a) of this article. This material must also be readily publishable to other TSOs and NRAs.
    c) The information under Article 23, item f, including supporting material. This information will not be published, except for percentage(s) stating the materiality like meant in Article 20.

26. Although the whole procedure is designed and meant to process claims from TSOs, the procedure is also open to NRAs in a similar way.

D. Method to treat upgrading, refurbishing and rehabilitation of assets in TCB18

Method to treat upgrading, refurbishing and rehabilitation of assets in TCB18

Background

In the benchmarking CAPEX is calculated as real annuities from full investments, valid for the duration of a standardized techno-economic lifetime across operators. Investments in the CAPEX correspond to assets reflected in the normalized grid. However, TSOs may also undertake partial investments during the life of an asset, e.g. upgrades or rehabilitation, that require specific attention.

In e2GAS TSOs report investment values per asset type and also possible upgraded investments by type, as described in Call C art 5.34-5.36 and in the template as described in Call C 7.09-7.10. In e3GRID the asset upgrades were processed by asset investment year and year of refurbishing, requiring information about age, intial investment and upgrading cost. Upgradings, refurbishing and rehabilitation are examples of partial investment

Types of partial investments

A TSO may undertake three types of partial investments, where part of the initial asset is retained in the new installation:

(i) Investment to change the dimension, power or other output features of the installation, e.g. an increase of the crossection on an existing overhead line or a change of compressor pumps to offer a higher power. We call this 'upgrading' in this note.
(ii) Investment to replace component(s) in order to achieve effects that are desirable but not counted as system outputs. E.g. retrofitting access protection or telecommunication antennas in towers. We call this 'refurbishing' in this note.
(iii) Investment to replace outdated or worn-out component in a system while keeping the residual components and not changing the output features of the installation. E.g., replacing the transmission lines while keeping the towers or replacing all control equipment in a station to permit interoperability and improved control. We call this 'rehabilitation' in this note.

The investments of type (i) are to be treated as normal investments where the original asset is removed from the asset database (X) and the new asset is added to the database (X) with the year of commissioning stated. The full value of the investment is kept in the investment stream, both for the initial and secondary investment.

The investments of type (ii) are not specifically addressed in the benchmarking, the associated cost is either OPEX (maintenance) or CAPEX (kept in normal investments, no change of asset description in X). To the extent that such upgrades would concern significant amounts and be triggered by regulatory imposition, this could be addressed as TSO specific elements in the benchmark.

Minor investments of type (iii) are part of normal maintenance; replacing worn-out components. These are kept in OPEX and trigger no change of the asset description in Call X.

Large investments of type (iii), see the threshold for that below, can be considered as 'significant rehabilitation' of an installation; a station or a line segment. Since no output data is changed, the investment would lead to a lowered CAPEX-efficiency if no adjustment is made. Although significant rehabilitations may have multiple objectives, intentionally these investments will be compensated for through a mechanism that considers it as resetting the age of the rehabilitated asset to zero.

Considerations

In defining a method for acknowledging significant rehabilitation of assets, attention should be paid to the tradeoff between the added complexity in reporting (for all) compared to the attained precision (for some TSOs) as well as the robustness to missing or unverifiable historial investment values for old assets.

To avoid a double system, introducing a strategic choice for operators, a simple approximation of the underlying asset value for the rehabilitated asset should be used.

Principle

An asset that is rehabilitated lowers the overall cost for the asset through spreading the real capex over a longer period.

Example:

- an asset with a standard techno-economic lifetime of 60 years is installed at an investment of 200 in year 0 in Figure 1 below. The capex annuity factor for this corresponds to about 2.87% per year with a real interest rate of 2%. Thus, the CAPEX for this item is 5.75 (2.87% of 200) per year until year 60 (red curve in Figure 1).
- Without other action, the asset is expected to die in year 60 at which time a new full investment of 200 (real) is necessary to replace the asset. Hence, the expected real annuity is 5.75 per year for as long as the system is in use.
- In year 35 the asset is subject to a significant rehabilitation at an additional real investment of 50. The asset state is restored as new and this implies that the economic life is prolonged to 35 + 60 = 95 years. The capex annuity factor corresponding to the incremental investment for this significant rehabilitation is 2.87% per year for the period 35 - 95, leading to an additional annuity of 1.44 (2.87 % of 50).
- In real terms, the underlying original investment still has to amortize 25/60 * 200 = 83.3. This is done over the period from year 35 to year 95 (60 years), hence, an annuity of 2.40 (2.87% of 83). So, effectively the CAPEX for the underlying investment is lowered from 5.75 to 2.40 for extended period 35-95.
- In total, the real CAPEX for this intervention is 3.84 (2.40 + 1.44) per year from 35 to 95, as shown by the blue curve in Figure 1.

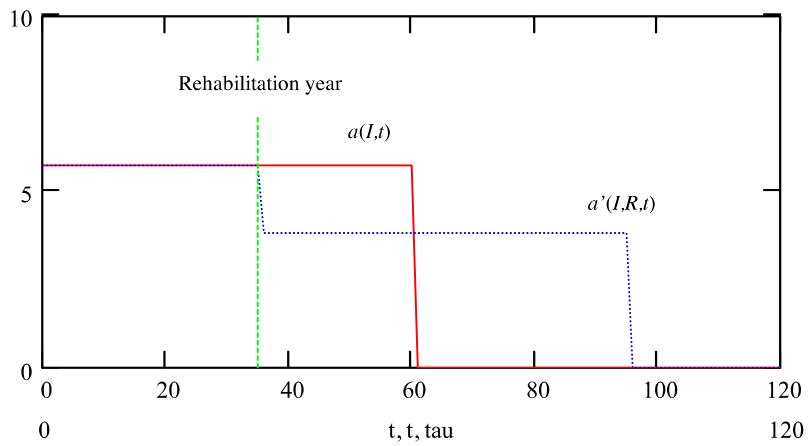

Figure 1 Annuities for example, significant rehabilitation in year 35.

Implementation

Consider in year t the choice of rehabilitating an asset invested at I € in year t_0 for R €, extending its life to T years.

In practice, the TSO may not be able to identify the specific investment I, either because it is part of a larger system (e.g. substation) or because it has been acquired at a bookvalue that has been modified through acquisitions, revaluations and other accounting operations.

To implement the method above, we may estimate the initial real investment value by using the normgrid share of the assets as key. Thus, in the initial investment year t_0 the specific intial investment corresponds to a normgrid value of g and the normgrid sum of all assets commissioned in that year is G and the real initial investment is given as IT, then the estimate of I is obtained as

$$I = \frac{g}{G} IT$$

since the normgrid metric is timeinvariant and IT is given in real terms.

The method above was implemented in e³GRID where assets are identified by year of investment. In e2GAS investment values were stated per year, but the individual assets had no age. Thus, the incumbent age of the underlying assets cannot be identified.

The real annuity a of initial investment I for a real interest rate of $r > 0$ is obtained as

$$a = I \cdot \left(\frac{r}{(1 - (1 + r)^{-T})} \right)$$

Investing R in a significant rehabilitation will increase the overall life to $T+t-t_0$ years for the underlying asset. The remaining (real) asset value is $I(T - (t - t_0))/T$. The new annuity for the rehabilitated asset (including both the old and new investments) is obtained as:

$$a' = \left(R + I \cdot \left(\frac{T - (t - t_0)}{T} \right) \right) \left(\frac{r}{(1 - (1 + r)^{-T})} \right)$$

Note that if the underlying asset has reached or is past its techno-economic life (i.e when $t \geq T + t_0$), the annuity is just equal to the rehabilitation investment as the initial investment is fully amortized.

Of course, the profitability of a significant rehabilitation depends its timing and magnitude. As illustrated in Figure 2 below for the same investment values as in the example above, a significant rehabilitation occurring already in year 10 would have a negative impact on CAPEX whereas a postponement of the rehabilitation to year 50 would have an additional positive effect.

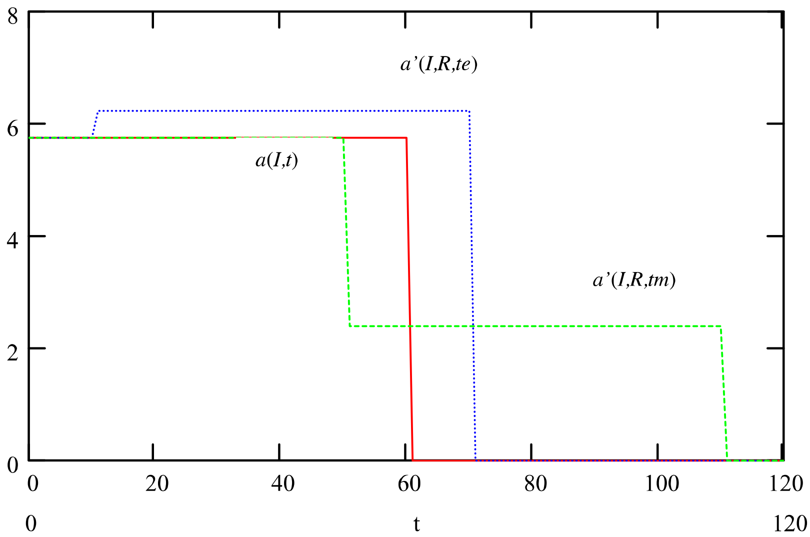

Figure 2 Example annuities for a (too) early (blue, t_e) and a very late (green, t_m) significant rehabilitation compared to base case (red).

Data requirements

The advantage of the proposed system is that incremental investments can be valued in the benchmarking without complex calculations. The following data are necessary:

(i) Aggregate investment value (nominal) per year, IT
(ii) Rehabilitation investment per asset category and year, *R*
(iii) Asset data for each rehabilitated asset, *g*
(iv) Commissioning year for each rehabilitated asset, t_0

For validation purposes the following date may also be desirable to have:

(v) Short description of the significant rehabilition per concerned asset

The limitations are that the underlying asset must still be identified by year of commissioning and the investments this year should correspond to the assets commissioned. As resort, a correction procedure with identification of the asset might be implemented.

Threshold

To distinguish normal maintenance from significant rehabilitation we propose that the incremental investment *R* should be at least 25% of the (real) underlying investment value, *I*.

E. Modelling opening balances and missing initial investments, 2018-01-11

2018-01-11 - PJA

Modelling opening balances and missing initial investments

Background

In a heavy infrastructure industry like the transmission of electricity, the efficiency of investments plays a very significant role in the overall evaluation of Totex efficiency.

This note explains how we can

a) make alternative measures that are less sensitive to historical capex efficiency and
b) analyze the sensitivity to opening balance adjustments.

We will explain how the investment streams shall be adjusted to accommodate such issues. The adjusted capital investment streams are used in the unit costs and DEA based models in the same way as the basic investment streams.

Problem analysis

The Capex measurement for benchmarking is repercussions on two relevant issues for benchmarking; incentive provision and structural comparability.

From the point of view of *incentive provision*, it is not obvious that the efficiency of historical investments shall continue to impair or benefit present management. It may be useful in some cases to forgive past investment inefficiencies in the overall evaluations, i.e. to consider investments before a given day as sunk cost that shall not influence today's efficiency. In particular, performance related to actions before deregulation or beyond the scope of managerial authority is less effective to provide incentives for current management.

A second problem relates to the benchmarking of, and towards, units with reestablished opening asset balances. In practice, this refers to TSO unable to produce historical investment streams due to late unbundling, reevaluation of assets, or that historical investment streams contain (fully depreciated) assets that are currently owned by other firms (distribution or generation). The investment stream for such firms therefore starts with a large opening balance investment followed by annual additions to the asset base.

A concern can be that the opening balances may be influenced by other than managerial factors, such as legal, political, regulatory and macro- economic factors prevailing at the time of the unbundling. If the opening balance is relatively low, the TSO may effectively be forgiven past investment inefficiency and if it is set relatively high, e.g. to pave the pay for capital cost reimbursement in a regulatory scheme, past efficiencies may be undermined.

Such phenomena are not necessarily a problem for the TSO itself. After all, we do not try to explain in details why some TSOs are more efficient than others, eg. due to careful planning and execution of the installation process, due to successful negotiations with asset providers, or due to market power in the acquisition of networks from previous owners. The opening balance might therefore reflect managerial skills.

On the other hand, the benchmarking should assure *structural comparability* among firms in the reference set. In particular, it should be possible to achieve the performance of TSOs designated as fully efficient peers without replicating exogenous and country-specific (political, fiscal) actions potentially involved in the establishment of an artificially low opening balance. The benchmarking should also be fair in the sense that units reporting a full historical investment stream should not be worse off than those merely reporting an opening balance.

Capex

Consider an investment stream I_t, $t = 0,\ldots, T$ for a given TSO (we suppress subscripts for TSO to simplify the notation). The investment in a specific year t concerns assets with a techno-economic lifetime of τ_t years. In the evaluations, the investment stream is transformed into a standardized constant annuity as follows

$$CAPEX = \sum_{t=0}^{T} \mathrm{I}_t^* \alpha(r, \tau_t)$$

where α is the annuity factor that spreads an investment as a constant cost over τ_t years when the interest rate is r, and I^* is the investment level we assign to year t. The difference between I_t and I_t^* is that the latter is transformed to EUR for a given reference year.

The capital investment corresponds to a technical asset base, the normalized grid unit, measured as

$$NormGrid_{CAPEX} = \sum_t \sum_a n_{at} v_{at} \alpha\,(r, T_{g(a)})$$

where n_{at} is the number of assets of type a installed in year t, v is the capex weight such an asset and $g(a)$ is the asset group that asset a belongs to (since we allow different techno-economic depreciation horizons for different asset groups). The normgrid can be seen as a sum of equivalent assets, e.g if v = 1 for 1 circuitkm overhead line of 300 kV at 500 mm^2 crossection, then v = 1.44 for 1 circuitkm overhead line of 300 kV at 900 mm^2 would mean that 144 circuit km of (300 kV, 500 mm^2) would correspond to an asset base equivalent to 100 circuit km of (300 kV, 900 mm^2). In the same manner, all assets can be summed to an equivalent measure of the size of the asset based, the normalized grid. As such, the normgrid is unitless, but it is usually calibration to average cost in a given reference year, thus NormGrid can be given an interpretation as average cost for a grid (capex or opex).

The capital investment efficiency is in general evaluated by considering CAPEX as an input that generates the output NormGrid_CAPEX. The Capex Unit Cost for example is simply the ratio of the two, i.e.

$$UC_{CAPEX} = \frac{CAPEX}{NormGrid_{CAPEX}} = \frac{\sum_t I_t^* \alpha(r, \tau_t)}{\sum_t \sum_a n_{at} v_{at} \alpha(r, T_{g(a)})}$$

Of course, the unit cost measure can be used as a single-dimensional (investment) efficiency measure in itself. The unit with the lowest UC would then be the most (investment) efficient, meaning that the Capex per equivalent grid unit is the lowest. An average TSO would have a unit cost of 1 with the standard calibration.

Opening balance adjustments

Consider a TSO where the investment stream is missing for all years before H. In year H, the TSO acquired an existing asset base for a (real) value of R.

As discussed above, this opening balance could be artificially *low* if the incumbent accepts a settlement below the (real) techno-economic depreciated value. This gives the TSO an idiosyncratic cost advantage that other operators cannot replicate with managerial action. If R is a large proportion of the CAPEX of the operator, the impact on the efficiency assessment may be important, potentially making the firm a peer for other firms. Since an efficiency target should be feasible, the Capex of a peer-firm with a biased opening balance must be corrected to protect the frontier.

A second possibility is that the operator has been forced to pay too much for the assets, i.e. an R that is above the average depreciated techno-economic value. This may occur in unbundling if the incumbent seeks an advantage in terms of capital structure. In this case, the operator is most likely inefficient and the frontier is unharmed. However, it is in the interest of the operator to obtain an estimate of the managerial efficiency obtained – excluding the idiosyncratic cost shock caused by the opening balance.

In both cases, we can obtain such estimate by calculating an estimate of the opening balance value R^* as if it was proportional to the unit-cost investment efficiency during the succeeding period, when the managerial action of the TSO has had influence over the outcome.

The Capex Break Method

Consider a TSO with an opening balance from year H at real value R. Since we know the composition of the asset base at the opening balance, the annuity for R can be obtained using an asset-weighted average techno-economic lifetime;

$$\mathrm{T}^* = \frac{\sum_a v_a n_a T_{g(a)}}{\sum_a v_a n_a}$$

The annuity then is given as:

$$Capex_R = R\alpha(r, T^*)$$

Let the NormGrid Capex for the assets acquired (after adjustments of age) for the period 0 to H be denoted $NG(0,H)$

The Capex Unit Cost for year H then becomes:

$$UC_{Capex}(0, H) = \frac{Capex\_R}{NG(0, H)}$$

We also have observed investment data for the period H+1, …, T. The average Capex Unit Cost for this period is calculated as:

$$EUC_{Capex}(H+1, T) = \frac{\sum_{t=H+1}^{T} \alpha(r, \tau_t)}{\sum_{t=H+1}^{T} \sum_a n_{at} v_{at} \alpha(r, T_{g(a)})}$$

Assume that the two unit cost measures are significantly different. Then a correction, the *capex break*, can be obtained by using the average investment unit cost also for the opening balance.

The Capex Break value is then calculated through:

$$Capex_{break} = EUC_{capex}(H+1, T) NG(0, H) + \sum_{t=H+1}^{T} I_t^* \alpha(r, T_t)$$

The idea of this adjustment is simple – if the TSO in the periods after H tends to be efficient and only spend 80% of the expected costs on its installations, we assume that this was the case prior to the opening balance also, and we use the asset register to reconstruct a likely historical investment stream. Hence, the logic behind the correction is based on the assumption that the investment behavior after the unbundling is the best indication of the managerial behavior prior to the unbundling.

Specific cases

The information situation prior to the opening balance may be different, leading to three solutions for the capex break calculation:

1. Commissioning years available for all assets in operation at time H
2. Average age available per asset group in operation at year H
3. Average age available for the entire asset based acquired at year H
4. No information exists on the age or state of the assets acquired before H

In case (1) the formulae above can be fully calculated.

In case (2) the formulae can also be used with minor modification without loss of precision.

In case (3) the initial NormGrid will have to use an average lifetime without any differentiation.

In case (4) the default estimate will be based on acquisition at full remaining lifelength at year H.

Application

For TSO without opening balance:	No application
For TSO with opening balance, peer:	Application in the reference set, not for the unit itself.
For TSO with opening balance, non-peer:	No application in the reference set, application in specific report.

As mentioned, the principle of application is to protect the frontier from peers that are characterized by non-replicable idiosyncratic cost-biases that render the overall cost targets and scores underestimated.

F. Norm Grid Development Technical Report, 2019-02-27 V1.3

Norm Grid Development

TCB18 PROJECT

TECHNICAL REPORT

2019-02-27 / ver V1.3

Disclaimer

This technical report describes methods and parameters used in the CEER TCB18 project.

This document may be updated and made available at Worksmart for project participants.

Norm Grid Development

Technical report, project release, version V1.3.

Project TCB18 / 370.

Release date: February 22, 2019

Version history

Version	Date	Status	Auth	Concerns
X1.0	2018-09-10	Draft	JT,JD	Prerelease for PSG PW3
X2.0	2018-09-21	Draft	PA	Second release for PSG
V1.0	2018-09-27	Final	PA	PSG review, release for W3
V1.1	2018-10-03	Rev	JD	Corrections to Elec part
V1.2	2018-11-13	Rev	JD,JT	Opex 4.1 – 4.7, new sections 2.9+2.12 Opex gas
V1.3	2019-02-21	Rev	JD	Red marks in 4.5, 4.4, 4.6, 4.7, 4.9.1, 4.9.2, 4.9.4

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1 The Norm Grid in Benchmarking

Prof. Per J. AGRELL and Prof. Peter BOGETOFT

1.1 Background

The modelling of transmission system performance necessitates a proxy measure for the size of the grid system. A simple counting of the assets (e.g. km of overhead lines or pipelines) would ignore differences in the cost of building and operating assets of different dimensions, leading to an underestimation of the size for those with assets larger or more powerful than the average operator. Thus, the proxy should be detailed enough to address the relevant scope of different asset types per energy. On the other hand, the proxy cannot be built to correspond to a specific brand or instance of assets or locations, as in a detailed catalogue model. The tradeoff between these two objectives: inclusion of relevant assets and dimensions, but aggregation across suppliers and specific installations, has been the study of benchmarking projects ever since ECOM+ in 2005 and subsequent projects for electricity and gas.

The construction of the proxy measure, the normalized grid (NormGrid) is based on relative ratios for capital and operating expenditure per asset type. In addition, environmental conditions must be taken into consideration when estimating the overall comparable size of the grid asset base.

This technical report describes

a) The construction of the norm grid measure in gas transmission,
b) The proposed environmental factors for gas transmission,
c) The construction of the norm grid measure in electricity transmission,
d) The proposed environmental factors for electricity transmission,

Care has been taken in the project management to provide a robust development process that can be repeated and adjusted for future use, as well as procedural transparency to promote cross-validation of system components by project participants.

1.2 NormGrid structure

In the method note TCB18 2018-01-11 "*Modelling opening balances and missing initial investments*" the normalized grid (NormGrid) is defined as a weighted sum of grid assets such as

$$NormGrid_{CAPEX} = \sum_t \sum_a n_{at} v_{at} \alpha\,(r, T_{g(a)})$$

where n_{at} is the number of assets of type *a* installed in year *t, v* is the capex weight such an asset and *g*(*a*) is the asset group that asset *a* belongs to (since we allow different techno-economic depreciation horizons for different asset groups). The NormGrid can be seen as a sum of equivalent assets, e.g if $v = 1$ for 1 circuitkm overhead line of 300 kV at 500 mm^2 crossection, then $v = 1.44$ for 1 circuitkm overhead line of 300 kV at 900 mm^2 would mean that 144 circuit km of (300 kV, 500 mm^2) would correspond to an asset base equivalent to 100 circuit km of (300 kV, 900 mm^2). In the same manner, all assets can be summed to an equivalent measure of the size of the asset based, the normalized grid. As such, the NormGrid is unitless, but it is usually calibrated to average cost in a given reference year, thus NormGrid can be given an interpretation as average cost for a grid (capex or opex).

The NormGrid structure is a greenfield system without any specific adjustments for environmental conditions, ageing or integration with non-grid systems (existing infrastructure; corridors, waterways).

The development of the NormGrid asset weights in electricity was based on systematic work in several international projects (ECOM+, e3GRID 2009, 2012) primarily by Sumicsid and CONSENTEC. As no public complete sources exist for these cross-asset comparisons, the initial work compiled different public and private sources used by operators and contractors in grid system planning. The current revision is reviewing the entire system by comparing the reference values, the functional form (linear/non-linear) and the optimal scale variables (voltage, crossection area, power, et c.).

For gas transmission, the seminal work in estimation was made by Sumicsid in the e2GAS project where a complete assessment was made of both greenfield and individual complexity factors by asset type. As for electricity, the work here involves consolidation of public and private sources used in planning and international assessments.

The calibration of the asset weight systems is made through linear regression towards the Capex and Opex data obtained in the project. This step scales the relative NormGrid metric towards average practice (not best practice) such that the relevant cost measures are attributed to the size proxy. Naturally, this means that the scope for both Capex and Opex are defined exactly as in the study.

1.2.1 Use of NormGrid in benchmarking

The NormGrid proxy can be used in several ways in assessing the performance of transmission system operators.

As an *output* the NormGrid represents the grid provision (complementary to flow or peak-related capacity utilization metrics) independent of the dynamic use of the grid. The underlying assumption for this approach is that any and all grid assets are providing some utility for grid users.

As an *input* the NormGrid be used as a proxy for capital expenditure, a cost that should be minimized for each level of exogenous output (typically flow, service and peakload measures). In this approach, serving grid users with a smaller or weaker grid for the same energy and capacity provision is seen as efficient.

In TCB18, the policy adopted by the NRAs is to promote past grid provision, quality provision and grid expansion investments. Hence, the intended use of NormGrid in this project is to form part of the outputs for the TSOs.

1.2.2 Validation of NormGrid

The validity of a proposed NormGrid parametrization can be tested in partial detail and as goodness of fit. A partial test could be to challenge the progression factors e.g. in voltage across transformers of a particular type by using data from tenders or installations with sufficient specifications. This might lead to corrections, if the data are more representative than the data used in the estimation. A goodness of fit analysis is testing the overall power of the NormGrid to explain Capex and/or Opex across real validated data for the operators, across time. The latter test is more important as the average effects prevail in the evaluation of TSOs, rather than detailed ratios that may point at particular installations that only form a minor part of the overall asset base.

1.2.3 Documentation for participants

The documentation for the NormGrid base weight system will consist in the following deliverables to project participants:

1. A note for the respective NormGrid system from the ELEC and GAS teams, respectively, including the principles of construction, the main sources, the points of possible revisions from earlier versions and some examples of the partial cost functions used.
2. Excel calculators for all relevant assets
3. Regression results for the goodness of fit of the specific NormGrid system towards Totex, Capex and Opex with the scope defined in the study, both standard and robust regression.

This report constitutes part (1) of the documentation and will be presented at W3. The final weight system including documentation (2) and (3) will be uploaded on Worksmart in the Common sections two or three weeks prior to W5.

1.2.4 Crossvalidation: NormGrid

The NormGrid system will be ready-to-use and released after tests and validation at levels at least corresponding to those in the previous projects e3GRID 2012 and e2GAS.

1.3 Environmental factors

It was decided in the TCB18 study to deploy an exogenous system where open sources are used to estimate environmental effects to prepare for long-term future use. The selection of factors for study is made by the engineering teams and is documented in this report.

The engineering teams (ELEC and GAS) initially screen and validate the eligible public factors that may have a techno-economic impact on the cost. These and only these factors are subject to econometric validation. A pure "data mining" approach might suggest country-specific factors (e.g. "language") without causality on cost, but fully capturing all country-specific residuals as "environmental". Naturally, this is of no relevance in this study, thereof the prior selection of candidate variables that technically can be claimed to have an impact.

1.3.1 Documentation and process

The documentation for the environmental factors will consist in the following deliverables to project participants:

1. A note from the engineering teams listing the sources and the candidate variables with full definition and their hypothesized cost impact on totex, capex and/or opex.

2. Estimation results from the econometric team for the candidate variables individually, as well as the retained factors with their numerical estimates and possible intervals of uncertainty,
3. Excel sheets with numerical factors per area or operator

This report contains part (1) of the documentation above for discussion at W3. Input from project participants may lead to the collection of additional or alternative factors, if relevant. The final environmental system including documentation (2) and (3) will be uploaded on Worksmart in the Common sections two or three weeks prior to W5.

Participants will be able to access the numerical values for the factors used for all other participants from the open sources used. In the case a TSO would find that a relevant open factor or source has been neglected or eliminated incorrectly, a request for completion or correction may be filed. In case of changes to the environmental factors, the deliverables (2) and (3) will be updated accordingly by the release of the final coefficients

2 Cost modelling GAS

Technical team GAS, headed by Jacques TALARMIN

Head of the gas system team, Jacques TALARMIN in Sumicsid has an double engineering degree from the University of Bretagne. After four years as a research engineer in CNRS, Mr. TALARMIN has been active over 33 years in gas transmission pipeline engineering, as Head of the Gas Transmission Pipeline Department, then as international expert for the World Bank, IEC and PENSPEN. He has made techno-economic evaluations of large scale gas transmission, LNG and gas storage projects in Belgium, France, Ireland, Italy, Norway, Portugal, Spain, Armenia, the Ivory Coast, Kazakhstan, Kuwait, (South Stream underwater), Bangladesh, Tunisia, Morocco, Iraq, Iran, Cameroon, Algeria, Turkey, Georgia, Jordan, Libya, Myanmar, et al. Ing. TALARMIN has been involved in Sumicsid projects for gas transmission including RAMIEL (Fluxys, BE), PE2GAS (CEER, 2014), E2GAS (2015-16), in the latter responsible for the development of the grid asset system.

The norm grid proxy for gas transmission assets is designed to be proportional to the construction costs of gas transmission pipelines.

After detailing the various expenses involved in the realization of a gas pipeline, in particular, the following cost items:

- Cost of material supply;
- Cost of pipeline installation and commissioning;
- Cost of miscellaneous works (project management, engineering, surveys, work supervision, etc.);
- Cost of damage during installation and operation
- In-line stations costs;

In the following, each of the categories are discussed to form the full cost function.

Besides some general sources (Page, 1977) there are very few published papers providing full cost functions for gas transmission assets under the TCB18 definitions. The analysis below is therefore based on our experience and proprietary data from numerous gas transmission projects and from valuation projects of transmission assets internationally. However, to demonstrate the face validity of our cost model, prior to and independent of the TCB18 data analysis, we include a quantitative analysis of a recent public study, ACER (2015) involving the operators in the TCB18 project.

2.1 Cost of material supply

2.1.1 Linepipes

The linepipe manufacturing process has been selected on the following base (see Figure 2-1):

- Seamless linepipes for D ≤ 4"1/2;
- 50 % High Frequency Welded (HFW) pipes and 50 % Longitudinally Submerged Arc Welded (LSAW) and Helical Submerged Arc Welded (HSAW) pipes for 6"5/8 ≤ D ≤ 24";
- 50 % LSAW pipes and HSAW pipes for 26" ≤ D ≤ 56".

D being the pipeline diameter generally expressed in inch (").

The average linepipes unit costs are as follows:

- 1300 €/t for seamless pipes;
- 800 €/t for high frequency induction (HFI) pipes;
- 1200 €/t for LSAW pipes;
- 1000 €/t for PSSAW pipes.

In the cost estimation of pipes, we will assume the average distribution of the following class locations:

For the pipes of diameter less than or equal to 16 "(ND 400):

- Rural areas :25%;
- Suburban areas: 50%;
- Urban areas: 25%.

For the pipes of diameter larger than or equal to 18 "(ND 450):

- Rural areas: 80%;
- Suburban areas: 10%;
- Urban areas: 10%.

It should be noted that the distribution of class locations indicated above is not strictly related to the external environment of the pipeline for small diameters.

Linepipes wall thicknesses have been calculated according to a MAOP of 71 bar(a) (70 bar(g)). Wall thicknesses distribution are shown in Figure 2-1.

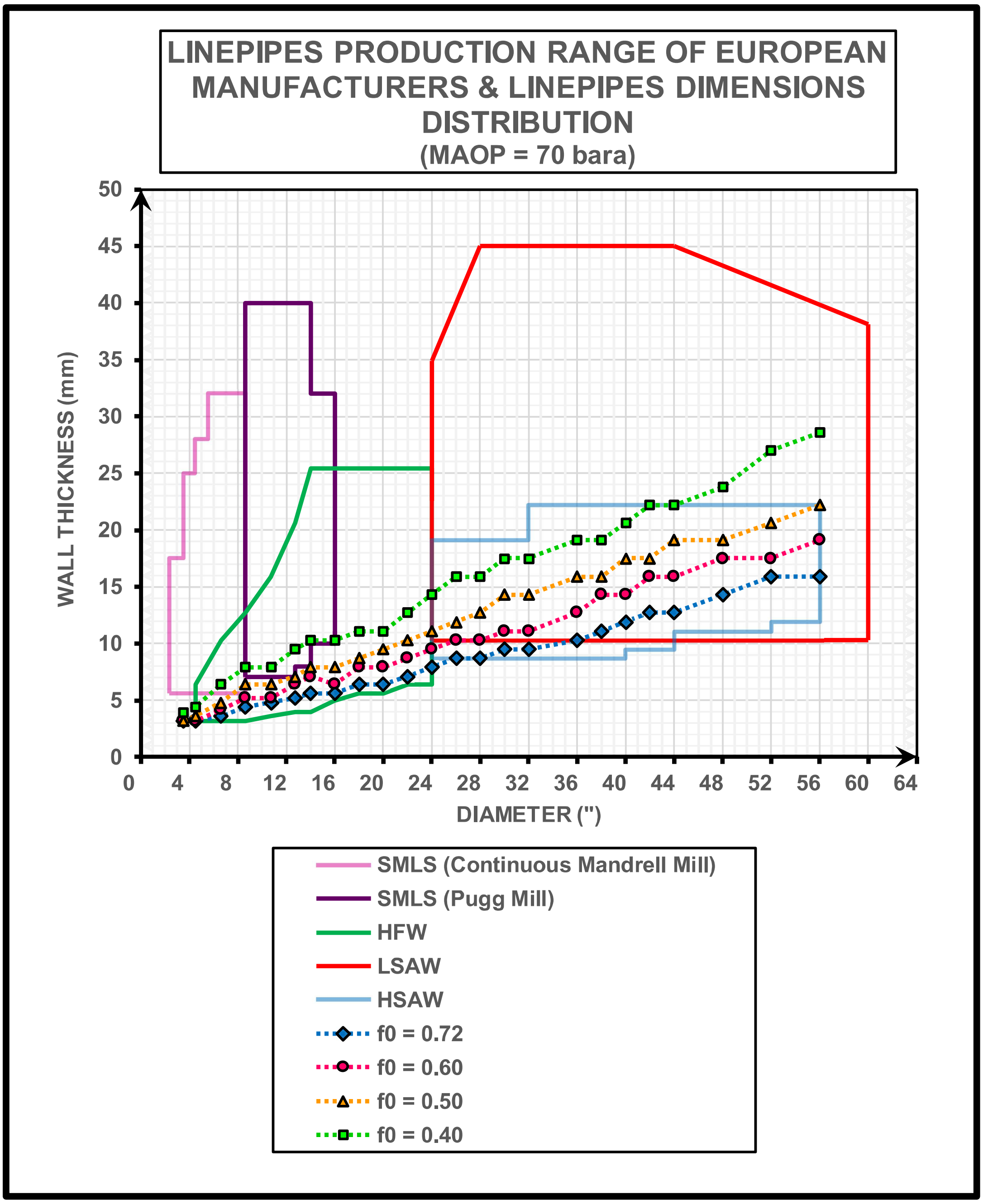
LINEPIPES PRODUCTION RANGE OF EUROPEAN MANUFACTURERS & LINEPIPES DIMENSIONS DISTRIBUTION
(MAOP = 70 bara)
WALL THICKNESS (mm)
0
5
10
15
20
25
30
35
40
45
50
0 4 8 12 16 20 24 28 32 36 40 44 48 52 56 60 64
DIAMETER (")
SMLS (Continuous Mandrell Mill)
SMLS (Pugg Mill)
HFW
LSAW
HSAW
f0 = 0.72
f0 = 0.60
f0 = 0.50
f0 = 0.40

Figure 2-1

2.1.2 Linepipe coating

2.1.2.1 External coating

Unit costs of external coating (3LPE) are ranged from 17 €/m^2 to 25 €/m^2 according to coating thickness which increases with the pipeline diameter.

2.1.2.2 Internal coating

It has been considered that the lining (which is intended to improve the flow of gas) is applied only for diameters equal to or greater than 16 ".

The average unit cost is estimated to 10 € / m2.

2.1.3 Miscellaneous supplies

Miscellaneous supplies (manufactured bends for example) are included in the supply cost and valued at 3% of the total linepipe cost.

2.1.4 Transport to site, unloading and storage

This cost is about 12/% of the supply cost.

2.2 Pipeline installation cost

The cost of pipeline installation, valued at 12.5 €/"/m, corresponds to a typical installation (not ideal or minimal cost). These costs include the crossing of special points (major crossings).

2.3 Miscellaneous costs

The miscellaneous costs, estimated at around 5 €/"/m, correspond to project management, surveys, engineering, supervision of construction work, owner expenses, and planning. These costs have been steadily increasing since the beginning of the 1990s mainly because of environmental and administrative constraints to obtain authorization to construct and operate the pipeline.

2.4 Damages costs

The costs related to the instruction and payment of direct damages caused during pipeline installation have been estimated at an average value of 1.2 €/"/ m. These cost exclude the capital costs of land and right-of-way, excluded from the TCB18 benchmarked capex.

2.5 In-line stations

The in-line stations are not considered separate assets, but parts of the pipeline system. The unit costs for sectionalizing valve stations (block valve stations) have been valued as shown below in Table 2-1 below.

Table 2-1

SECTIONALZING VALVE STATIONS				
Diameter			Cost	
"	mm	ND	€	€/"
3 1/2	88.9	80	96 098	27 457
4 1/2	114.3	100	104 481	23 218
6 5/8	168.3	150	112 489	16 979
8 5/8	219.1	200	142 204	16 487
10 3/4	273.1	250	154 404	14 363
12 3/4	323.9	300	167 727	13 155
14	355.6	350	205 437	14 674
16	406.4	400	240 856	15 053
18	457.2	450	257 997	14 333
20	508.0	500	304 477	15 224
22	558.8	550	327 329	14 879
24	609.6	600	347 891	14 495
26	660.4	650	384 844	14 802
28	711.2	700	419 888	14 996
30	762.0	750	454 551	15 152
32	812.8	800	503 655	15 739
36	914.4	900	551 635	15 323
38	965.2	950	583 106	15 345
40	1 016.0	1 000	614 882	15 372
42	1 066.8	1 050	646 880	15 402
44	1 117.6	1 100	676 595	15 377
48	1 219.2	1 200	738 308	15 381
52	1 320.8	1 300	801 554	15 415
56	1 422.4	1 400	860 984	15 375

The cost of pig trap stations (one launcher and one receiver) is obtained by multiplying the cost of sectioning stations in Table 2-1 by a coefficient of 3.5.

The cost of cathodic protection stations and corresponding on-line control equipment has been estimated by multiplying the cost of sectionalizing valve stations by a factor of 0.4.

The following assumptions have been made for the distribution of these in-line stations along the pipeline route:

- 1 sectionalizing valve station installed every 20 km;
- 1 pig launcher and 1 pig receiver installed every 100 km;
- 1 Cathodic Protection Station installed in half of the sectionalizing valve stations perimeter, i.e : approximately one station every 40 km. The cost of cathodic protection therefore represents approximately 0.5% of the total construction price of the gas pipeline.

The average total cost of in-line stations (including Cathodic Protection stations) is in the range of 1.2 to 1.4 €/"/m.

2.6 Pipeline total construction cost

Based on the elements above, we can now derive the total construction cost (€/km) of a gas pipeline is shown in Figure 2-2 below as a quadratic function of the pipeline diameter D (")

- Pipeline Construction Cost (€/km) = 420.3693 D^2 (") + 12,126.1250 D (") + 100,432.6361 (1)

If we consider the variation of unit cost expressed in €/"/m, we can see that this cost decreases rapidly for small diameters from nearly 50 €/"/m, then goes through a minimum of about 25 €/"/m for a diameter of 12 "3/4 before increasing almost linearly to reach nearly 38 €/"/m for a diameter of 56".

The average unit cost of construction of the line is of the order of 29.8 €/"/m.

This cost includes in-line stations with an average unit cost of around 1.3 €/"/m, so the overall cost of the line without in-line stations is about 28.5 €/"/m.

The relative importance of the different pipeline construction cost items is as follows:

- Materials supply 32.6 %
- Pipeline Installation 41.5 %
- Miscellaneous works 16.6 %
- Right-Of-Way 4.2 %
- Inline stations 5.1 %
- Total 100.0 %.

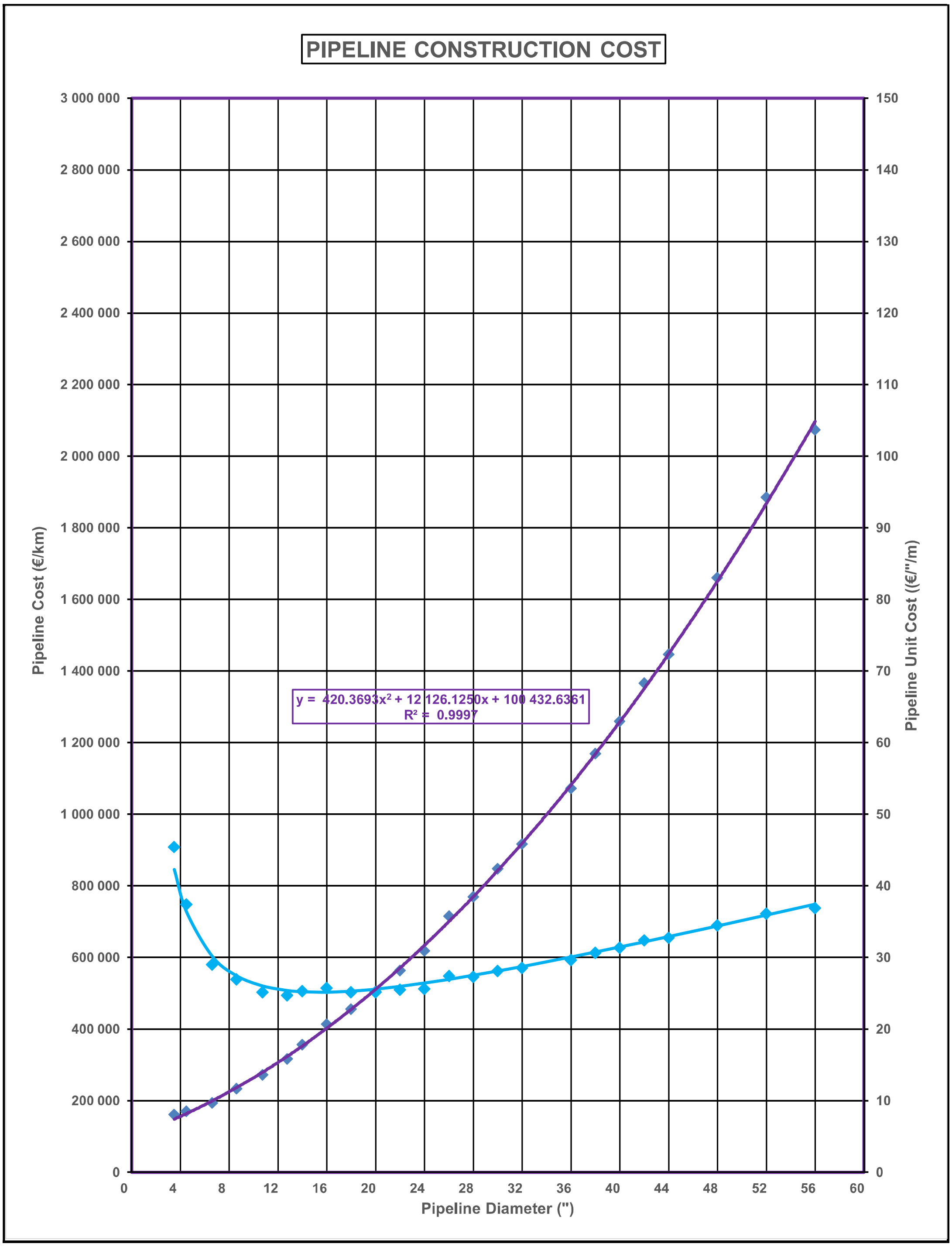
PIPELINE CONSTRUCTION COST
y = 420.3693x² + 12 126.1250x + 100 432.6361
R² = 0.9997
Pipeline Cost (€/km)
Pipeline Unit Cost ((€/"/m)
Pipeline Diameter (")
3 000 000
2 800 000
2 600 000
2 400 000
2 200 000
2 000 000
1 800 000
1 600 000
1 400 000
1 200 000
1 000 000
800 000
600 000
400 000
200 000
0
150
140
130
120
110
100
90
80
70
60
50
40
30
20
10
0
0
4
8
12
16
20
24
28
32
36
40
44
48
52
56
60

Figure 2-2

2.7 Validation on ACER data

ACER carried out a study of the investments related to transmission networks in 2015, ACER (2015).

These investments were classified into the following two items:

- Pipelines;
- Compressor stations.

The pipeline cost item therefore includes all the investments relating to the realization of a transmission system (line pipe supply, pipeline installation, engineering, work supervision, ROW, in-line stations, corrosion protection equipment, metering and pressure reducing/regulating stations, interconnection stations, telecommunications, control centers, maintenance centers, spare parts warehouse, etc.).

The results of the ACER study are summarized in Figure 2-3. This graph represents the cost of pipeline construction (€/"/m) in relation to its diameter (").

The first observation that can be made is the very strong dispersion of data: the price per km of a pipeline may vary from 1 to 5 for many diameters. This variability can be explained at least partially by the external environment in which the pipeline is constructed.

The second observation relates to the average unit price (€/"/m) of pipeline construction which is in the range of about 42 to 44 €/"/m, or about 50 USD/"/m; which seems high. It is possible, however, that these costs may be explained by the fact that the pipeline cost item includes all the implementation costs listed above, while in general, the cost of pipeline construction is limited to the line, in-line stations and corrosion protection equipment.

From these data, ACER proposed average costs in €/km (indicated by green circles on the graph). It is then possible to calculate the following relation according to the diameter:

- Pipeline Construction Cost (€/km) = 935.655 D^2 (") – 13,922.435 D (") + 589,595.980 (2).

ACER data were then averaged for each of the diameters (indicated by red diamonds on the graph). These averages have established the following relationship between the pipeline construction cost (€/km) and the outside diameter (") with a correlation coefficient of 0.905:

- Pipeline Construction Cost (€/km) = 642.985 D^2 (") + 2,464.295 D (") + 398,135.326 (3)

It can be noted that the two curves are close. However, the relationship (3) defines better the costs at both ends of the graph, so for small diameters and large diameters.

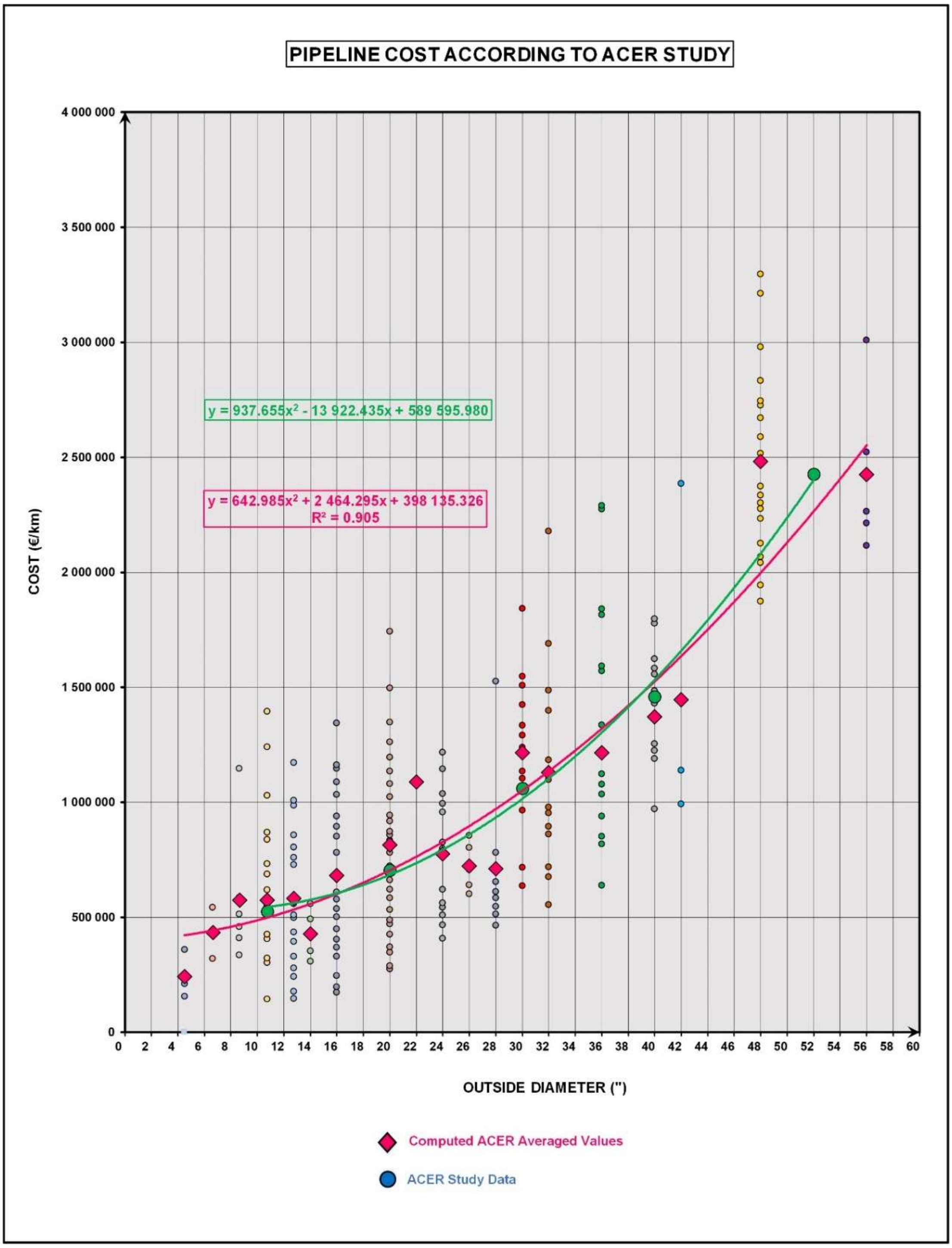
PIPELINE COST ACCORDING TO ACER STUDY
y = 937.655x² - 13 922.435x + 589 595.980
y = 642.985x² + 2 464.295x + 398 135.326
R² = 0.905
COST (€/km)
OUTSIDE DIAMETER (")
Computed ACER Averaged Values
ACER Study Data

Figure 2-3

2.8 Comparison with ACER data

The costs estimated in ACER (2015) are higher than those proposed by our analysis. The differences observed mainly concern diameters less than 20 "and are greater than 30%. For diameters greater than 20", the cost differences are between 17% and 27% (see Figure 2-4).

These differences are primarily explained by the fact that ACER costs for pipelines include all transmission system facilities with the exception of compressor stations. The ACER costs therefore include metering and pressure regulation stations, interconnection stations, remote control and command of pipeline system (SCADA and telecommunications), etc., which are evaluated separately in this study. The cost of these facilities, not included in the cost of the present study, can be estimated between 10% and 15% of the total pipeline cost and therefore cannot explain the differences observed for small diameters.

In addition, we note that the cost scenario in ACER(2015) in fact is for a relatively difficult installation site. Consider below the distribution of costs between the different items involved in the construction cost of a gas pipeline is as follows in the ACER study:

- Materials supply 33 %
- Pipeline Installation 49 %
- Miscellaneous works 12 %
- Right-Of-Way 6 %
- Total 100 %.

The ratio of the Installation / Supply items is 1.50, which with international data indicates a difficulty above average because of the relative importance of construction works compared to supplies of equipment. We recall that the norm grid weights in TCB18 are based on a construction site of average difficulty.

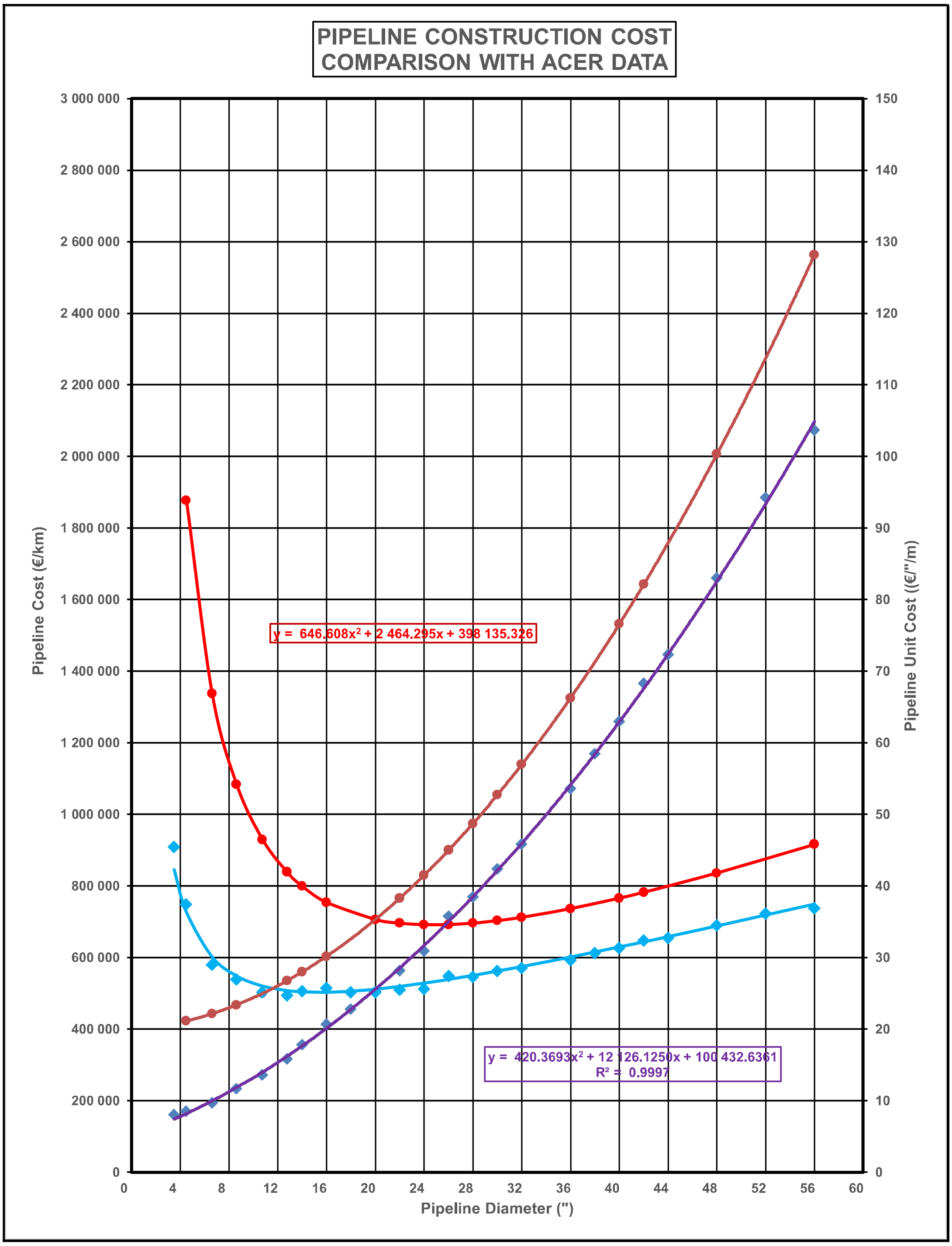
PIPELINE CONSTRUCTION COST
COMPARISON WITH ACER DATA
y = 646.608x² + 2 464.295x + 398 135.326
y = 420.3693x² + 12 126.1250x + 100 432.6361
R² = 0.9997
Pipeline Cost (€/km)
Pipeline Unit Cost ((€/"/m)
Pipeline Diameter (")
3 000 000
2 800 000
2 600 000
2 400 000
2 200 000
2 000 000
1 800 000
1 600 000
1 400 000
1 200 000
1 000 000
800 000
600 000
400 000
200 000
0
150
140
130
120
110
100
90
80
70
60
50
40
30
20
10
0
0
4
8
12
16
20
24
28
32
36
40
44
48
52
56
60

Figure 2-4

2.9 Compressor costs

The Compressor Station cost mainly depends on the capacity of installed machines and on the type of machines:

- Centrifugal compressors driven by gas turbines or electrical motors
- Reciprocating compressors generally driven by gas engines,
- Other types (not frequent)

Our cost function, illustrated in Figure 2-5 is based on a study conducted in the US and published in 2012. Costs were updated in 2017 using the following Nelson-Farrad indexes:

- Compressors
- Labor (construction)
- General inflation

The costs in € were obtained taking into account the average exchange rate with the US dollar in 2017. The study involves only gas turbine drivers.

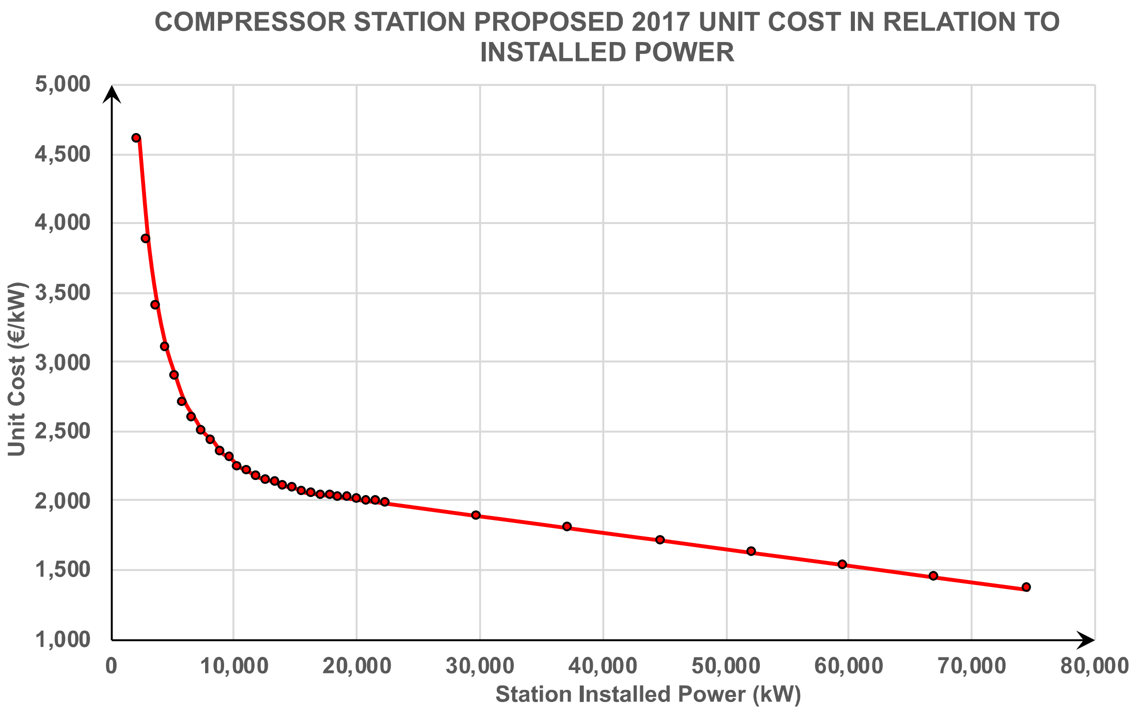

Figure 2-5

The cost function above is built on proprietary international data. Thus, as validation we use the ACER study from Europe is used. The graph in Figure 2-6 compares the proposed unit costs with the results of the ACER study and the data provided by the Spanish NRA (the only one to have transmitted complete and reliable cost data on their gas transmission network).

Note (in the graph) that ACER only provides averaged unit costs (flat curves) and does not take into account the variation of the unit cost with the installed capacity, which leads to maximizing the unit costs associated to large compressor stations and to minimizing unit costs of small compressor stations.

The Spanish data correspond to the reality of compression unit costs but are a little lower than the costs that we propose for gas turbines in 2017.

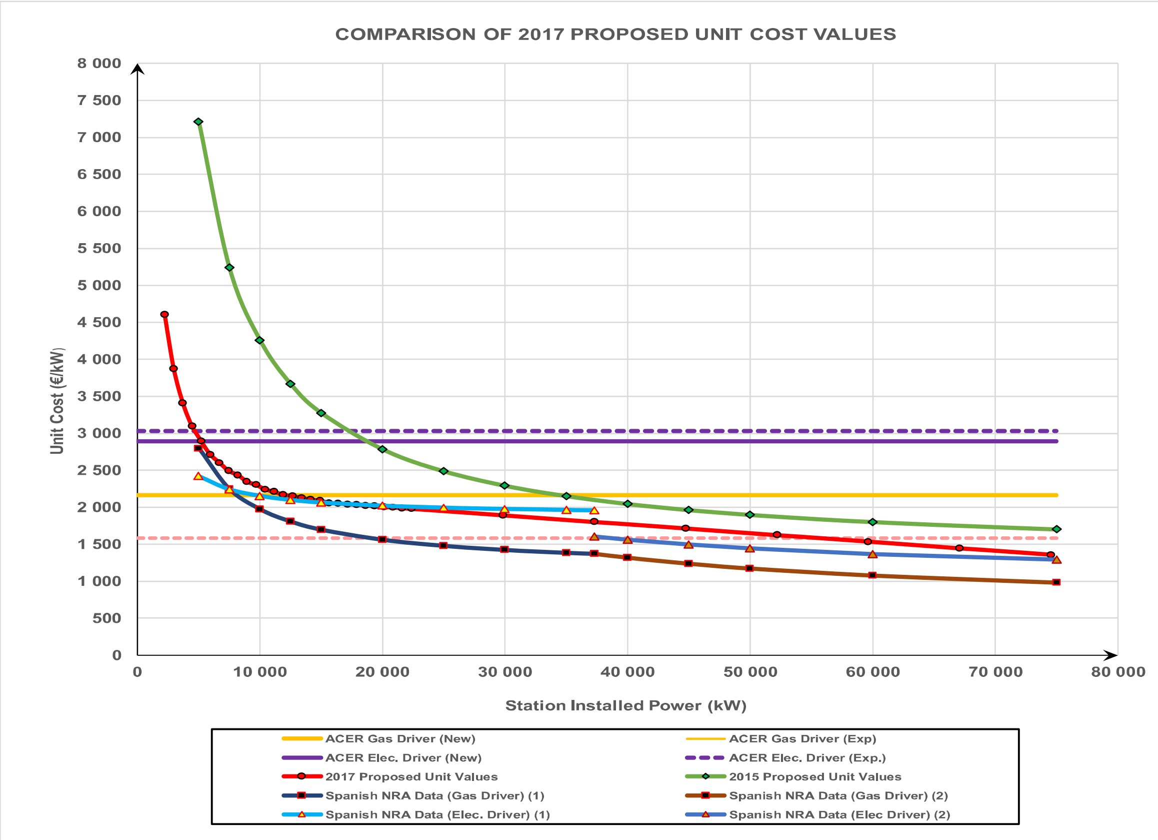

Figure 2-6

In Figure 2-7 the costs are recalculated for a compressor station as a function of installed power. As expected, the economies of scale give a concave cost function that can be estimated using a nonlinear cost function. However, we note that a simpler and more linear function provides an almost perfect fit.

Thus, we retain the following formula for compressor station CAPEX as a function of total installation capacity by

- $\text{Cost}(P)_{gas} = 1{,}359\ P + 10{,}368{,}790$ (€)

where P = Installed capacity (kW ISO, gas turbines).

With regard to **electric drivers**, it is necessary to take into account the cost of power lines, transformers, etc.; which may significantly increase the price of these facilities. The average cost, we have in hand, concerns stations of 25 - 32 MW and is in the range of 2800 to 3350 €/kW, which corresponds to the values indicated by ACER. We propose consequently the following formula :

- $\text{Cost}(P)_{elec} = 3{,}000\ P$ (€)

where P = Installed capacity (kW ISO, electric engines).

For the reciprocating compressors (both gas and electrical drivers), the cost function is defined as with a power function for best fit:

- $Cost(P)_{rec\text{-}comp} = 2.2 \cdot 33{,}860\ P^{0.714}$ (€)

where P = Installed capacity (kW ISO).

Finally, the class of 'other' compressors: for smaller compressors (≤ 10 MW) of other types than the ones mentioned above, the cost function $Cost(P)_{rec\text{-}comp}$ applies, for larger compressors (> 10MW) we use $Cost(P)_{gas}$.

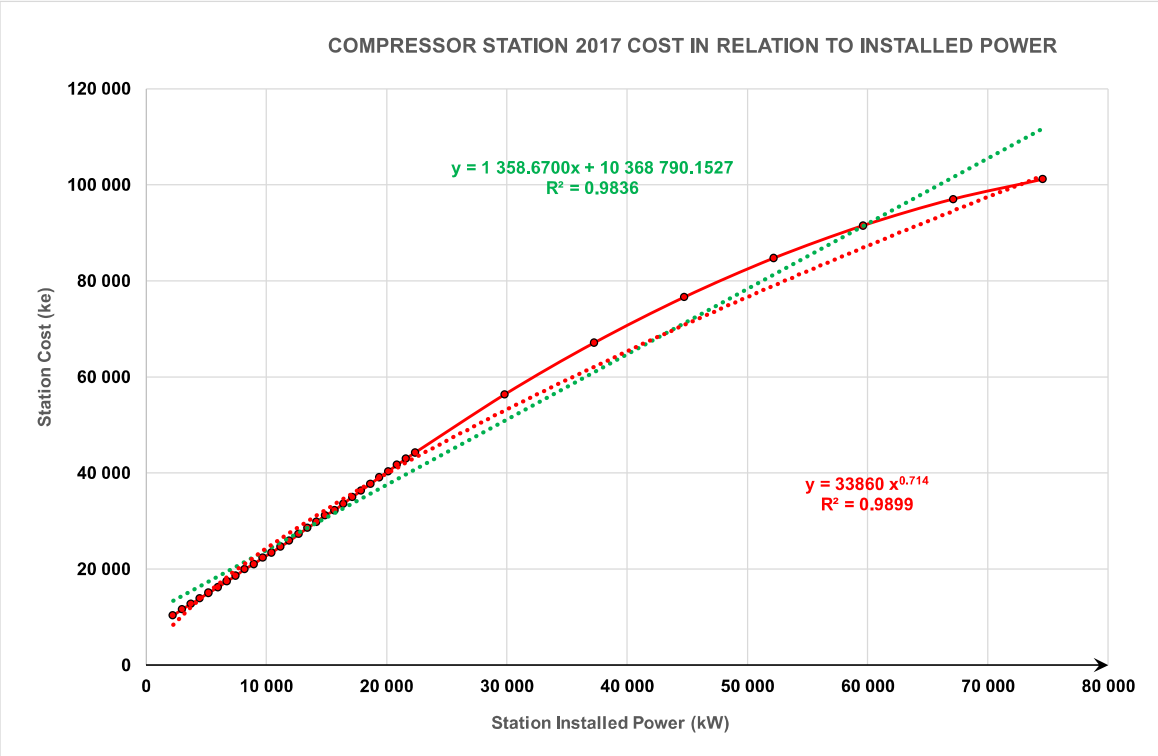

Figure 2-7

2.10 Costs for Pressure Regulation and Metering Stations

The investment costs for Pressure Regulating and Metering Stations have been estimated using proprietary data from a mid-size French TSO. Concerning piping, valves and fittings, electrical and civil engineering (supply & installation), conventional ratios have been used to determine costs. 10% have been added for engineering. The resulting cost function depends on the total flow rate as:

- Cost(Q)prms = 799.84 x $Q^{0.5503}$ (€)

Where Q = Total Flow Rate (m^3(n)/h).

Fit with international metering stations in France for pipeline and stations connected to underground storage: 0.94. The specific cost for gas heating facilities is not included in data (estimated max +10%).

2.11 Costs for Control Centers

Based on the control center costs for a complete renovation of a control center (including a back-up center) of a medium-sized operator (5000 km of lines; several compressor stations; underground storage facilities, international network, the cost is estimated to € 2.5M€.

2.12 Operating and maintenance cost

The exact operating expenditure (OPEX) for operations and maintenance of the assets is not uniquely defined by existing external documents, since the full OPEX also includes elements related to overhead and allocation of costs from other functions and their equipment. However, the percentages in (OPEX excluding energy expenses) are indicative of the relative costs of OPEX per asset category.

Table 2-2

Facilities Designation		OPEX (% of investment present value)
Pipeline (incl. in-line stations & Cath. Protection)		2.00
Compressor Stations	Type 1 (Gas Turb + Cent. Comp.)	6.00
	Type 2 (Elec. Mot. + Cent. Comp.)	3.50
	Type 3 (Gas Eng. + Recip. Comp.)	5.50
	Type 4 (Elec. Mot. + Recip. Comp.)	3.00
Metering & Pressure regulating/control stations		3.50
System telesupervision (SCADA, telecom., Cont. Cent.)		7.00

3 Environmental modelling GAS

Technical team GAS, headed by Jacques TALARMIN

This chapter relates to the determination of environmental factors, mainly related to the external environment of the pipeline, affecting the construction costs of the pipelines.

Traditionally, the overall cost of pipeline construction can be broken down into the following 4 items:

- Supply of materials and equipment;
- Pipeline installation and commissioning;
- Miscellaneous works (engineering, project management; owner expenses; etc.);
- Right-of-Way operations.

For each of these four operations involved in the construction of the pipeline, an analysis of the factors (cost drivers), related to the external environment of the pipeline that could change the cost of these operations, was carried out.

These cost drivers have been listed and quantified for the supply of materials and pipeline installation items. But, it was not possible to perform the same evaluation for miscellaneous works and Right-of-Way items due to the lack of data available on this subject. It should be noted, however, that the relative importance of these last two items in the overall pipeline construction cost of the pipeline should not exceed 20 -25%.

Knowing the relative importance of the four operations involved in the construction of the pipeline, it was possible to determine the influence of each cost driver on the overall base price of construction of the gas pipeline.

3.1 Pipeline cost breakdown

Pipeline construction costs is generally split into the following four items:

- Supply of materials;
- Pipeline installation;
- Miscellaneous;
- Right-of-Way.

3.1.1 Materials supply

This cost item relates to the purchase and on-site transportation of all materials and equipment related to the pipeline construction.

3.1.2 Pipeline installation

This cost item relates to the cost of construction, pre-commissioning and commissioning of the pipeline and associated in-line stations.

3.1.3 Miscellaneous

Miscellaneous costs correspond to those associated with engineering, surveying, work supervision, project management, overhead, contingencies, financial expenses, etc.

3.1.4 Right-of-way

Right-of-way (ROW) costs in TBCB18 include costs linked to wayleaves, damages, permissions, but not land acquisition and capitalized right-of-way easements.

3.2 Factors influencing the materials supply costs

3.2.1 Cost breakdown

Supply cost item can be broken down into the following sub-items:

- Coated linepipes,
- Other materials
    - Prefabricated bends,
    - Pig trap and block valves materials,
    - Branch line connection materials,
    - Cathodic protection equipment,
    - Fibre optical cables laid in the pipe trench, if any.
    - Etc.

3.2.2 Linepipe

As a general rule, linepipes used for gas transmission are made of carbon steel.

Factors involved in the sizing of the wall thickness of linepipes are as follows:

- The design pressure, or maximum operating pressure (if similar);
- The outside diameter,
- The design factors,
- The Specified Minimum Yield Strength (SMYS).

For a given pipeline where the design pressure and the outside diameter are defined, the sizing factors are therefore limited to design factors and to SMYS.

We can also add the selected linepipe manufacturing process that can possibly differ from one TSO to another.

3.2.2.1 Design Factor

The design factors are specified by the safety regulations in force. These design factors are linked to the urbanisation degree and population density in the immediate vicinity of the narrow corridor within which the pipeline is constructed.

Safety regulations are defined on a European scale, in general, but are supplemented by national or sometimes regional or provincial regulations. The design factors may be consequently slightly different from one country to another.

It can be considered that, on average, the design factors vary as follows depending on the increasing population density:

- F = 0.72 for thinly populated areas, i.e.: rural areas;
- F = 0.60 for intermediate densely areas, i.e.: suburban areas;
- F = 0.40 for densely populated areas, i.e.: urban areas.

It should be observed that the linepipes wall thickness for a given diameter and design pressure is directly proportional to the inverse of the design factors. We can therefore consider the following cost drivers depending on the urbanization of the external environment of the pipeline and their quantification as noted in the following Table 3-1.

Table 3-1

Cost Driver Urbanisation Degree	Cost Factor
Urban area (densely populated)	1.80
Suburban area (intermediate densely populated)	1.20
Rural area (thinly populated area)	1.00

In addition, it is known that some TSOs, possibly within the same country and normally subject to the same regulatory obligations, may go beyond the sole requirements of the regulations in force. Such additional obligations may, for instance, lead to increasing pipe wall thickness in order, first, to improve the safety of the gas transmission pipeline system, and secondly, to face a possible evolution of urbanization after pipeline commissioning. Despite that, it should be noted, that the general philosophies for calculating pipe wall thickness applied from one country to another are very close and there is no need to consider the slight differences that may exist in this field.

3.2.3 Specified Minimum Yield Strength (SMYS)

The SMYS depends on the steel grade selected by the TSOs. It must be noted that, for pipelines of similar dimensions, the steel grades of higher mechanical strength are, in principle, less expensive than the lesser mechanical strength steel grades; as the pipe wall thickness is inversely proportional to the steel SMYS for a given pipeline diameter and design pressure.

It can be, however, assumed that for a given diameter and design pressure, one should not observe a large variability in the choice of steel grades among the different TSOs. Moreover, the available steel grades are normally defined by the same standard in Europe and differences, if any, are expected to be limited to some additional requirements, defined by the specifications of TSOs, and which do not lead to significant cost variations.

3.2.4 Linepipe Manufacturing Process

Likewise, linepipes can be manufactured by different methods (seamless linepipe, welded linepipe with longitudinal or spiral welding, and with or without filler material). Unit costs of linepipe vary according to the selected manufacturing process; seamless pipes, for example, are normally more expensive than welded pipes. However, it can be assumed that for a given pipe dimension, the choice of the manufacturing process should not be fundamentally different from one TSO to another.

3.2.5 External Corrosion Coating

In the past, the linepipe external coating was tarred [coal tar (CTE) or asphalt (AE) enamels] and these coatings could be applied on site.

Currently, linepipes for on-land pipelines are coated at the factory by either tri-layer high density polyethylene (3LHDPE) or fusion bonded epoxy (FBE).

Differences are observed in the choice of the external corrosion coating but should not have a significant impact on overall supply costs.

3.2.6 Internal Coating

The internal lining (applied to improve the gas flow) is recommended, in general, for pipes which diameter exceeds a Nominal Diameter (ND) of 400 mm (or 16 ").

Even if TSOs philosophies for limiting pressure losses in networks can be different, the impact on overall supply costs is not significant.

3.2.7 Other materials

Other materials (manufactured bends, in-line stations valves, piping and fittings cathodic protection, etc.) do not represent an important portion of the total linepipe costs and, therefore, should not lead to significant cost discrepancy among the TSOs.

It shall be observed however that the distance between two successive block valve stations is also linked to urbanization: the regulation, imposing, for safety reasons, a reduction of this distance when the degree of urbanization increases. However, we have no reason to believe that the slight differences that may exist in this area can lead to significant cost variations from one TSO to another.

3.3 Transportation to site, unloading and storage

3.3.1 Transport of coated linepipes

Linepipes are manufactured in factories located in places geographically highly variable in Europe (Northern France, Germany, Greece, Italy, UK, etc.). Depending on their origin and their destination and on the means of transportation (railways, sea, etc.), the linepipe transportation costs may be different.

However, possible cost variations observed among the TSOs should not have a significant impact on the overall cost of supplies given the international market conditions and the number of international suppliers.

3.3.2 Unloading and storage on site of coated linepipes

Costs of linepipe unloading and storage of coated linepipes on construction site are insignificant compared to the cost of pipe supply and therefore possible variations among TSOs are not expected to be important.

3.3.3 Transport, unloading and storage on site of other materials

Transportation, unloading and storage of other materials and pipeline related appurtenance supplies (bends, materials for in-line stations, cathodic protection, etc.) account for a small part of linepipe ones and should not consequently really affect the supply total cost.

3.4 Total linepipe costs

The only source of variability of the linepipe supply cost (ex-factory) essentially depends on the design factors used in the calculation of wall thicknesses. Design factors depends mainly on the degree of urbanization of the immediate pipeline environment which imposes a most severe line sizing in the densely population areas therefore in urban and suburban areas than in rural areas.

Except the materials and equipment related to corrosion protection, the main part of other materials (bends, materials for in-line stations) are also sized according to design factors mentioned above.

It can be considered that the transportation of linepipes to site, unloading and storage to site depend mainly on their weight which is also inversely proportional to the design factors as the supply cost.

The cost of purchasing materials and equipment other than linepipes and their transport and storage on site are not always strictly related to the factors of urbanization defined above for the linepipes. But the expected costs are low compared to the linepipes purchase cost and it can therefore be considered with a good approximation that the cost drivers governing the purchases of linepipes and other materials used in the construction of the pipeline are defined above.

3.5 Factors

Estimating the cost of constructing a pipeline is a difficult subject because it is directly related to the characteristics of the external environment in which the pipeline is laid.

In addition, it must be observed that the environment of a pipe is not homogeneous along its route and that using average characteristics is the only feasible approach without resorting to detailed reporting of each pipeline segment.

3.6 Asset location factor

The country, region or province in which a pipeline is built may also influence its installation and operating costs. The weather conditions may also influence the work productivity. However, note that the labor cost differences are corrected through indexes in the study and not considered here. In addition, the environmental conditions are addressed through separate data.

3.7 Factors affecting pipeline installation cost

Traditionally, the factors influencing the installation cost of a pipeline can be broken down according to the difficulties encountered on the route as follows:

3.7.1 Factors linked to surface features

(i) Land use classified as follows:

- Unproductive areas (open country or desert);
- Agricultural areas (including pastures and cultivated areas);
- Industrial areas;
- Degree of urbanization:
    - Urban areas (densely populated);
    - Sururban areas (intermediate densely populated);
    - Rural areas (thinly densely populated);
- Special Scientific Interest areas (SSI areas) (including national, provincial or regional environment protected areas, archaeological areas, etc.).

(ii) Relief classified as follows in order of difficulty:

- Flat;
- Undulating (slope < 10 %);
- Hilly (10% < slope < 30 %);
- Mountainous (slope > 30 %

(iii) Soil humidity classified as follows in order of difficulty:

- Dry;
- Occasionally wet or floodable;
- Permanently wet or flooded;
- Swampy;
- Peaty.

(iv) Vegetation classified as follows in order of difficulty:

- Grassland;
- Bushes;
- Shrubs;
- Woods;
- Forests.

The vegetation factor was not considered during the last benchmarking exercise, although it is a key factor to consider when assessing the cost of construction of a pipeline. It can be verified that vegetation does not appear in any of the factors (i) to (iii) and (v) used in the previous benchmarking analysis.

3.7.2 Factors linked to subsurface features

(v) Subsoil properties classified as follows in order of difficulty:

- Loose
- Stony
- Soft rock;
- Medium rock;
- Hard rock.

3.7.3 Factors linked to special construction works

It shall be noted that when the work to be done requires special studies and means of construction beyond the means currently available in the construction spread, the corresponding areas are then classified into special points or special areas (or major crossings). The assessment of the major crossings cost can be based on the cost of similar achievements made before. The major crossings correspond to, but not limited to, the following obstacles:

(vi) Major crossings

- Major roads or highways;
- Wide railways;
- Large rivers and canals;
- Large ponds or lakes;

- Mountain massifs;
- Forest massifs;
- Etc.

Crossing of very congested areas, for example, are also often considered as major crossings when it is necessary to implement special construction processes to cross them (directional drilling or tunneling).

3.7.4 Sources of pipeline installation cost factors

There are no comprehensive scientific papers on the environmental impact on pipeline cost and the occasional engineering reports found in open domain are mostly disparate, incomplete and sometimes undoubtedly underestimate the relative cost increase of the obstacle to which it refers. There is of course, the book published by J. S. Page (cost estimating manual for pipeline and marine structures) but it is old and the cost drivers only correspond to pipelines laid in open country only. The crossing of mountainous areas has been the subject of more recent publications such as, for example, Gasca and Sweeney (2005).

In the absence of comprehensive and reliable publications, the cost drivers and associated cost factors, listed below in Table 3-2, have been determined based on detailed and existing cost tables for pipeline construction that we had at our disposal. In a number of cases, these data are proprietary and cannot be published.

A difficulty coefficient of 1 corresponds to the construction of a pipeline built on a flat land and not involving any difficulties or constraints of construction.

A difficulty coefficient is established for each of the factors listed above to quantify the difficulties that can be envisaged. This coefficient, greater than 1, represents the cost supplement associated with each of the cost drivers listed above. For example, a cost factor of 1.20, associated with an agricultural zone, means that the cost of pipeline installation is increased by 20% when it must cross such an area.

Precautions must be taken in applying the cost factors defined above. It is often difficult to describe the reality of the terrain with the precision mentioned in the cost drivers indicated above, especially for the geo-mechanical soils characteristics. This often leads to the application of an intermediate cost factor between two of the cost drivers mentioned above.

3.8 Factors for miscellaneous costs

As mentioned above, miscellaneous costs correspond to those associated with engineering, surveying, work supervision, project management, contingencies, expenses, etc.

We have no reason or data suggesting that these costs would be driven by any identifiable environmental exogenous factor.

3.9 Factors for associated costs

Costs linked to wayleaves and land acquisition, damages, permission granting to build and operate the pipeline, etc., are obviously variable according to the regulations and the cost of land in the countries traversed by the pipelines. The land price (if relevant) is excluded, the other costs are assumed to be proportionally constant among operators

These costs should be in the range of 3 to 8% of the total price of pipeline construction but there is no available data indicating that these costs would be determined by any exogenous factors.

However, possible variations of these costs will not be considered as we do not have accurate information in this area.

3.10 Relative importance of pipeline cost items

The four cost items considered above were allocated as follows throughout the overall pipeline cost in accordance with the values reported in ACER (2015):

- Materials supply : 33 %;
- Installation works : 49 %;
- Miscellaneous : 12 %;
- Right of Way : 6 %;
- Total : 100 %.

It may be objected that these weights can normally vary according to the diameters and design pressure of the pipes, but ACER(2015) is, if not the only study carried out on an European scale, at least the most recent and the most complete in this field.

3.11 Cost drivers for total pipeline cost

Knowing the weight associated with each item cost item in the total cost of pipeline construction, the possible variations of cost depending on the external environment of the pipe associated with each of these items, it is possible to obtain the values indicated in the table. following Table 3-2. It is these cost indications compared to the overall cost of the pipeline that are, in general, published.

A difficulty coefficient has been established for each of the factors listed in Table 3-2 to quantify the difficulties that can be envisaged. This coefficient, greater than 1, represents the cost supplement associated with each of the cost drivers listed in this table. For example, a cost factor of 1.10, associated with an agricultural zone, means that the cost of pipeline is increased by 10% when it must cross such an area. This cost increase of 10 % is only an average in agricultural areas, sometimes, it can exceed this value for crossing of rice fields, orchards, vineyards, etc.

Precautions must be taken in applying the cost factors defined above. It is often difficult to describe the reality of the terrain with the precision mentioned in the cost drivers indicated above, especially for the geo-mechanical soils characteristics. This often leads to the application of an intermediate cost factor between two of the cost drivers mentioned above.

Finally, we recall that the present analysis is prescriptive in the sense that the factors and dimensions described are those ideally identified and reported at the lowest possible level. This report does not address the definitions and availability of publicly available data to assess these factors, nor the possibility to adjust definitions to finer or more coarse resolutions.

Table 3-2

COST DRIVERS & ASSOCIATED COST FACTORS / PIPELINE TOTAL BASE COST						
FACTORS LINKED TO SURFACE FEATURES						
No.			DESCRIPTION	MIN	MEAN	MAX
1			**LAND USE**			
	1		Unproductive area (open country or desert)	0.90	1.00	
	2		Agricultural area (pasture and cultivated area)	1.05	1.10	1.25
	3		Industrial area		1.30	
	4		Urban area (densely populated)		1.75	2.20
	5		Suburban area (intermediate densely populated)		1.25	
	6		Rural area (thinly populated area)		1.05	
	7		Special Scientific Interest areas (SSI) (including national, provincial or regional environment protected areas, archaeological areas, etc.).	1.10	1.25	2.20
2			**TOPOGRAPHY**			
	1		Flat		1.00	
	2		Undulating (slopes < 10 %)		1.15	
	3		Hilly (10 % < slopes < 30 %)		1.35	
	4		Mountainous (slopes > 30%)	1.50	2.25	4.90
3			**SOIL HUMIDITY**			
	1		Dry		1.00	
	2		Occasionally wet or floodable		1.15	
	3		Permanently wet or flooded		1.35	
	4		Swampy	1.40	1.65	2.20
	5		Peaty	Not estimated		
4			**VEGETATION**			
	1		Grass		1.00	
	2		Bushes		1.05	
	3		Shrubs		1.10	
	4		Woods		1.35	
	5		Forests (ø > 20 cm)	1.40	1.60	2.20
FACTORS LINKED TO SUBSURFACE FEATURES						
5			**SUBSOIL**			
	1		Loose		1.00	
	2		Stony		1.15	
	3		Soft rock		1.35	
	4		Medium rock		1.50	
	5		Hard rock		2.20	
FACTORS LINKED TO SPECIAL CONSTRUCTION						
6			**MAJOR CROSSINGS (Difficulty Coefficient > 3.5)**			
	1		Major roads and highways			
	2		Wide railways			
	3		Large Rivers and Canals			
	4		Lakes			
	5		Mountain massifs			
	6		Forest massifs			
	7		Others			

Note **When the difficulty coefficient exceeds 3.35, the obstacle to be crossed must be normally considered as a special zone.**

3.12 References GAS

ACER (2015) ACER Report on Unit Investment Cost Indicators and Corresponding Reference Values for Electricity and Gas Infrastructure. Final report. https://www.acer.europa.eu

Gasca, A., & Sweeney, M. (2005). Pipelining in rugged terrain: costs, cost drivers and routing principles. In *International conference on: Terrain and geohazard challenges facing onshore oil and gas pipelines:* Proceedings International conference on: Terrain and geohazard challenges facing onshore oil and gas pipelines., London, UK, on 2–4 June 2004 (pp. 555-570).

Page, J. S. (1977) *Cost Estimating Manual for Pipelines and Marine Structures*. Elsevier.

4 Cost modelling ELEC

Technical team ELEC, headed by Dr. Jacques DEUSE

Head of the TCB18 electricity transmission system team, Dr DEUSE is PhD in power systems and working for Sumicsid since 2011 as electricity transmission expert, previously Chief Engineer in Tractebel Energy Engineering, responsible for among other projects the development of the STAG (EUROSTAG) software, the TACIS projects ERUS 9411, EREG 9601, as well as the TSO-smart grid project EU-DEEP in the European FP7. He has lead and participated in power system development projects in Belgium, France, Spain, USA, Chile, Peru, New Caledonia, Dubai, Oman, Saudi-Arabia, et al., both operations and asset deployment. For Sumicsid, he was leading the engineering development in the ECOM+ project (2004-05) and the following e^{3}GRID projects (2007-08 and 2012-14), in particular the development of the cost weight system for electricity TSOs and the operator-specific assets

4.1 Development

This chapter provides some detail about the Norm Grid construction for electricity transmission systems. Where do these components come from and how have they been updated for the present project? The chapter does elaborate on the role of the Norm Grid in the benchmarking process itself, already discussed in Chapter 1.

4.1.1 Past

In a first step, a collection of asset types is developed. Such collection must be able to represent at the right level of detail (as detailed as necessary, but remaining as simple as possible) the type of system under consideration: here the electrical power system. In a second step, a cost weight system must be developed that will permit to set up the Norm Grid.

In 2005, for ECOM+, the first benchmark implemented by Sumicsid, the collection of items necessary for building the Norm Grid was inherited from a previous project. At that time, the power system team put its best knowledge at disposal of the project, working as much as possible in continuation with what was implemented earlier. Some structures of the first project, like parts of the asset system classification, are still used in TCB-18.

4.1.2 Present

From ECOM+ to TCB-18 the cost weight system has been built using practically exclusively a *top-down approach*. This means that costs were coming from the compilation of costs from previous high-voltage power systems investments. Naturally, cost observations from real installations are also influenced by factors not modelled initially, such as environmental factors and other operator-specific factors.

For TCB-18 these sets of data have been first updated to present conditions and, further have been completed by publicly available data, but also private data from experts in the field. It is worthwhile to note that a significant part of these new sources of information are based on a *bottom-up approach*. This means that costs are determined from elementary costs of sub-components.

This means that for TCB-18 two different approaches have been jointly used to set-up the cost weight system. Further, the discrete asset classes (e.g. voltage classes) in use in previous projects have been replaced by continuous values for voltage, power and short-circuit breaking currents.

4.2 General principles and sources

Cost weights for TCB-18 have been rebuilt from ground up. As starting point, the raw data used for the previous projects, and particularly from the 2005 project. This basic information has been adjusted to present conditions. Further, these data have been compared and completed using recent public data (see references), but also, for significant part of them, confidential data updated in June 2017.

The integration and consolidation of all these information result in a finer grain system of weights leading to potential better valuation of Norm Grid values.

For this updated approach, it seems worthwhile to note three significant sources:

- The seminal work is from CIGRE (1991), "Parametric Studies of Overhead Transmission Costs" - CIGRÉ Working Group 09. This publication remains a significant contribution for what concerns the "cost structure" of overhead lines. This type of "collaborative work" is unfortunately rare.
- The work performed in the framework of CIGRE in Parsons Brinckerhoff (2012) Study, working in association with CCI Cable Consulting International Ltd for the Institution of Engineering and Technology;
- The reports Black and Veatch (2012, 2014) for the Western Electricity Coordinating Council (WECC);

In addition, an extensive set of public access sources from EU, USA, Canada, UK, Australia, (see references below), has been used to revise estimates and to extend the power ranges of OH Lines and Cables. Further to the range extension, merging these data with the ones already available in the "e3GRID (2013) mean cost database" is an indirect way for database validation.

Finally, the system has had access to proprietary databases from *Global Electricity Transmission Report* for a large range of international projects, albeit with a lower level of detail than used in this study. Detailed data for the Gibraltar Strait connection (31.5 km, 700 MW AC) has led to updates for the cable function.

Most of the O&M costs are based on data from the Norwegian Weight System. Order of magnitude of NGET data for O&M for OH Lines, UG Cables, transformers are similar.

Weight parameters for under-sea Cables have been partly determined using Norwegian Weight System.

For Under-Sea Cables additional data should be necessary for evaluating the rating reduction due to reactive power generation by the cables (for UG Cables, compensating means are regularly installed along the cable route and the corresponding costs are considered in the compensating devices list.)

4.3 Overhead Lines

Initially, in the ECOM+ Project, the weights for Over Head Lines and Under Ground Cables were set up using two basic variables : operating voltages and nominal currents, with as entries, voltage and current ranges. For the second and third applications (e3GRID 2009 & 2013) currents have been replaced by nominal power for OH Lines and UG Cables. This gave rise to new entries for the database of weights for OH Lines and UG Cables, but weights remained, in principle, unchanged, inflation adjustment excluded.

For the present project this approach is confirmed and the process has been restarted from scratch, while keeping the same macroscopic approach. This assures continuity in reporting and updates for relevant cost functions.

Two circuits lines have been considered as the reference, essentially in connection with the new collected data. The power range of these two circuits lines is now extended to about 9000 MVA.

In the updated model, the cost per km is a quadratic function of the rating of the line expressed in MVA. The basic cost has been set-up for two circuits lines.

- $\text{Cost}(\text{k€/km})_{\text{Base}} = 150 + 0.534 \times \text{Rating} - 3.3\text{x}10^{-5} \times \text{Rating}^2$, with Rating in MVA.

This is the base cost, the "effective" cost depends on the length of the line that is built. The following formulae are used, based on a solution from the Spanish NRA (triple and twin):

- For lines with triple bundle: $\text{Cost}(\text{k€})_{\text{Line}} = \text{Cost}(\text{k€})_{\text{Base}} \times (\text{km} + 1.7)$
- For lines with twin bundle: $\text{Cost}(\text{k€})_{\text{Line}} = \text{Cost}(\text{k€})_{\text{Base}} \times (\text{km} + 0.7)$
- For lines with single conductor: $\text{Cost}(\text{k€})_{\text{Line}} = \text{Cost}(\text{k€})_{\text{Base}} \times (\text{km} + 0.3)$

Assumptions :

- the base is 2 circuits lines, factors have been set-up for 1 circuit & multiple circuits line,
- this weight is defined for "mean conditions", that is to say partially open, semi-rural or semi-urban land, and undulating terrain with reasonably flat sections,

Additional factors :

- factors related to land, icing, extreme temperatures, peaking during summer, etc. (see information on environmental parameters),

Remark :

Due to the balance of cost for accessories and their installation compared to the cost of the tower, the reduction of circuit cost for multiple circuits lines is limited to two circuits. This means that circuit cost does not reduce for lines with more than two circuits. The reduction factor for one circuit is $1.25^{-1} = 0.8$.

One circuit line cost = 0.8 x 0.5 x Cost of a two-circuit line (which is the base for TCB-18).

For a two-circuit line with only one circuit installed, the circuit cost is 0.8 of two-circuit line, and when the second circuit is installed, the cost is 0.3 of two-circuit line (this is in line with the position of the NRA in Spain that admits a 110% cost for a 2 circuits line when the second circuit is built afterwards.)

OPEX : 3.7 (k€/km-year).

4.4 Underground cables

The cost per km is defined by two linear models, one valid for low rating and the other for high rating, the formula is based on synthetic isolation cables (here noted PEX):

- $\text{Cost(k€/km)}_{\text{Base}}$ = max{(3.1081 x Rating + 383) ; (5.725 x Rating – 2059)}, with rating in MVA
- $\text{Cost(k€)}_{\text{PEX Cable}}$ = (Line length (km) + 1) x $\text{Cost(k€/km)}_{\text{Base}}$, one km is added to the line length for taking account of "fixed costs", essentially cable terminals.
- $\text{Cost(k€)}_{\text{Oil Cable}}$ = 1.41 x $\text{Cost(k€)}_{\text{PEX Cable}}$.

Additional factors:

- Formula is based on synthetic isolation cables
- Factors related to land, etc. (see general information about that elsewhere),
- Tunnels, the way cables are laid down, etc.

Remarks:

- special laid down conditions when multiple cables are required could lead to significantly higher costs
- this is also the case when special conditions have to be fulfilled, like installation under roads with light, medium or high load, using stabilized compounds, etc.

OPEX_{PEX} = 1.4 (k€/km-year).

OPEX_{OIL} = 2.0 (k€/km-year).

4.5 Undersea cables

In the present revision, the formulae of UG Cable are used for determining the undersea (US) cable costs $\text{Cost(k€/km)}_{\text{BaseUS}}$ and $\text{Cost(k€)}_{\text{CableUS}}$.

$\text{Cost(k€/km)}_{\text{BaseUS}}$ = 1.35 x $\text{Cost(k€/km)}_{\text{Base}}$

$\text{Cost(k€)}_{\text{CableUS}}$ = (Line length (km) + 8.5) x $\text{Cost(k€)}_{\text{BaseUS}}$,
8.5 km are added to the undersea line length for taking account of higher fixed costs.

OPEX_{US} = 0.15 (k€/km-year).

4.6 Transformers

The first step consisted of parameters adjustment of the data from e3GRID (2013) to obtain basic costs for present conditions. Inflation index has been used to that end. In a second step, external costs information coming from other sources have been compared and partially merged with initial updated data. This allowed for setting up a complex cost model based on rating and voltages of transformer windings.

- Cost(k€) = Rating x [(377 x Rating$^{-0.701}$) x (0.834 x e $^{(0.00249 \times V1)}$)+ 0.014 x V_2]

With $V_1 > V_2 \geq V_3$, primary, secondary (and tertiary) voltages in kV ; Rating in MVA. The transformer is supposed to be equipped with on load tap changer.

Additional factors :

- Autotransformer : 0.90,
- Phase shifter : 1.15,
- Without on load tap changer : 0.85,
- Power Shifter Transformer: only V1 is given, ($V_2 = V_1$ in formula).

Remark : another feature that can be linked to the nature of the transformer is « single phase » or « three-phase » but this was not considered for this project.

$OPEX_{TRAFO}$= 6.5 + 0.0323 x V_1 (kV) (k€/year).

4.7 Circuit ends

Two busbars "Open air" substations are used as base (this is directly related to data used for developing the model).

- $Cost(k€)_{Base}$ = 306.5 + 4.395 x Voltage (kV)

In a second step the current breaking capacity is introduced,

- $Cost(k€)_{BB}$ = $Cost(k€)_{Base}$ x (0.01325 x Current (kA) +0.725).

Then, the factor related to the type of substations :

- 1 bus : 0.79
- 2 buses : 1.00
- 3 buses : 1.21
- 4 buses : 1.37
- 1 ½ breaker : 1.19
- 1 bus, no breaker: 0.10

Further, the distinction between "Open air" and "Closed" substations, in case of "closed" substation: this factor (function of voltage) is given by :

- 0.66 ln(Voltage) + 0.8797, Voltage in kV, used for bay isolated in "air".

And finally, the factor for "Metal Clad – GIS" : this is also a function of voltage :

- 0.445 ln(Voltage) – 0.329, Voltage in kV, valid for "closed" cases.

- 0.66 ln(Voltage) + 0.8797, Voltage in kV, valid for "open" cases.

Circuit ends weights have been compared with those found in publications from the USA, but also from private documents from Brazil. Comparisons are not straightforward because substation configurations in these countries differ from those in Europe. However, for similar situations, costs figures are in close agreement.

It seems worthwhile to note that it is now possible to introduce longitudinal and transverse coupling of bus bars. Initially, substations were not considered explicitly and, consequently, the costs corresponding to bus bars and their coupling were implicitly included in the circuit-ends weights.

$OPEX_{CIRCUITENDS}$= 45% of annuity (k€/year).

4.8 Compensating Devices

International data, e.g. Black & Veatch (2014), combined with updated weights, lead to the weights in Table 4-1 below.

Table 4-1 Compensating devices.

Type	Cost	OPEX
Fixed shunt capacitor	5 k€/Mvar	0.51 k€/year
Variable shunt capacitor	17.5 k€/Mvar	0.51 k€/year
Fixed shunt reactor	21 k€/Mvar	0.51 k€/year
Variable shunt reactor	21 k€/Mvar	0.51 k€/year
Variable shunt capacitor – inductor	(should be split in reactor and capacitor)	
SVC	75 k€/Mvar	0.5% investment /year
Statcom	104 k€/Mvar	0.5% of investment /year
Synchronous compensation.	75 k€/Mvar	1% of investment /year
Series capacitor	27 k€/Mvar	0.5% of investment /year
Series inductor	22 k€/Mvar	0.5% of investment /year

4.9 HVDC Installations

For HVDC installations the same approach as the one used for e3GRID 2013 is prolonged as far as data are delivered.

4.9.1 HVDC cost for Line Controlled Converters

The retained cost function is given by:

- Cost LCC (k€ per converter): 395 x $\text{Rating}^{1-0.183}$, with Rating in MW,

Cost Maximum cost could be: 485 x $\text{Rating}^{(1-0.1932)}$, idem,

Considering California, P&B report and EU: 304 x $\text{Rating}^{(1-0.1719)}$.

Remark : Costs given by Siemens show a constant cost of about 60 k€ per MW from 1000-1500 up to 3000-6000 MW. This is perhaps questionable as there is no size effect anymore.

$\text{OPEX}_{\text{HVDC-LCC}}$= 0.7% of investment / year.

4.9.2 HVDC cost for Voltage Source Converters:

- Cost VSC (k€ per converter): 340 x $\text{Rating}^{(1-0.0992)}$, with Rating in MW

This value is selected using the highest given by ENTSO-E (2011) (in that case for a power of about 500 MW at 300 kV) and from the costs proposed by Parsons Brinckerhoff (2012) for transfer of 3000 and 6000 MW for a bipolar connection at ±320 kV. Taking account of the large power, a number of modules are operated in parallel. Cost in this case decreases only slightly with size. This was not the case for the different low power variants proposed in a proprietary study for Suriname made by A. Hammad, at that time from ABB Switzerland (values used in ECOM+, 2005).

Important variati ons can be expected in this domain : for instance the costs of very similar installations can vary from 1 to 2.

$\text{OPEX}_{\text{HVDC-VSC}}$= 0.7% of investment / year.

4.9.3 HVDC overhead lines

The cost weight for of HVDC overhead lines is based on the weight for HVAC line of the same ratings.

A reduction factor from AC to DC based on Black & Veatch (2014) is set to 0.478. Further this is adjusted for an "equivalent voltage", that is to say the peak phase to ground voltage in AC equals the pole voltage in DC. The OPEX is identical to that for HVAC lines.

4.9.4 HVDC undersea cables

Weight is calculated for LLC and VSC installations operated at about 320 – 400 kV. Variations of the cost per MW x km remain below 3.5% when comparing LLC 3000 MW and 6000 MW, 400 kV bipolar connection, with VSC 3000 MW and 6000 MW, 320 kV bi-pole. So a single weight is considered in a formula that includes the cost dependence versus line length.

Formula for single cable:

- $Cost_{SINGLE}$ (k€) = 1.742 Rating x (length + 8.5), Rating in MW, length in km.

The 8.5 km in excess of line length correspond to the incidence of fixed costs.

- $Cost_{BICABLE}$ (k€) = 2 $Cost_{SINGLE}$, for bi-pole cable.
- $Cost_{TRICABLE}$ (k€) = 3 $Cost_{SINGLE}$ if a neutral (reserve) cable is installed.

This weight leads to good order of magnitude for costs, but fluctuations in cost can be quite large for individual installations for various reasons:

- The market conditions at the moment of construction (relative scarcity of specific hardware, ship, etc.),
- Distance from cable production site to installation,
- Special mechanical protection that could be required for the cables,

In PSC (2014), some installations have been compared that use Polymer cables (used with VSC) and Mass Impregnated cables (that presently must be used for LCC). Mass Impregnated cables seem less expensive (ratio 1240/1480 = 0.84).

This has been determined from installations of rather short lengths, hence the incidence of fixed costs is perhaps playing a role which cannot be evaluated using available data.

$OPEX_{HVDC\text{-}US\text{-}CABLE}$= 0.15 k€/km-year.

5 Environmental modelling ELEC

Technical team ELEC, headed by Dr. Jacques DEUSE

Environmental conditions influence the investment cost for, in particular overhead lines and underground cables, to a lesser extent the costs for transformers and other assets. As discussed below, the relevant factors are a subset of those already described for gas transmission pipeline construction. Operating costs, including maintenance costs, are affected by a some additional factors by virtue of the location and configuration of the assets (height and exposure to wind, salt and sun). We close the section with some suggestions for these additional factors that could complement the analysis.

5.1 Common factors for gas and electricity

For what concerns the electricity part of the project, cost weights are developed considering "mean conditions." If overhead lines are taken as an example, this leads to an "average line." The basic weights that will be used are not considering green field conditions, with flat land, no obstacle, etc., but *average* conditions that are considered the more probable for a significant part of the system. In TCB-18, it means that overhead AC lines are supposed to be installed:

- In gently undulating land;
- With towers that are of the suspension type for 70% of them;
- With basic span capacities that are utilized to about 80%;

These conditions can be considered as typical for construction through partially open, semi-rural or semi-urban land, and undulating terrain with reasonably flat sections;

Sensitivity analyses give tools that allow for adjusting weights for more or less demanding conditions.

For this project, open access data will be used for each country for adjusting the cost weights to national environmental conditions with respect to land use, topography and subsoil structure (see above). These factors are already mentioned in the section for gas transmission installations, Chapter 3.

The use of the land use and topography factors is common also in electricity, cf. the table below from Black and Veatch (2014) gives cost factors for the selected types of environment in California. It is worthwhile to note the significant variation of some of these factors across the different Companies (Pacific Gas & Electric, South California Edison, San Diego Gas & Electric, etc., and the resulting mean values adopted by WECC). Note that the exact adjustment factors may not apply in TCB-18, depending on the granularity and availability of public European data in this regard.

Table 2-5 Terrain Cost Multipliers

TERRAIN	PG&E[3]	SCE[4]	SDG&E[5]	WREZ	WECC
Desert	1.00	1.10	1.00	-	1.05
Scrub / Flat	1.00	1.00	1.00	1.00	1.00
Farmland	1.00	1.00	1.00	1.10	1.00
Forested	1.50	3.00	-	1.30	2.25
Rolling Hill (2-8% slope)	1.30	1.50	-	-	1.40
Mountain (>8% slope)	1.50	2.00	1.30	-	1.75
Wetland	-	-	1.20	1.20	1.20
Suburban	1.20	1.33	1.20	-	1.27
Urban	1.50	1.67	-	1.15	1.59

For underground cables, a similar approach is used. The derivation of weights is made analogously to the gas pipeline construction, the full set of factors in gas may also apply for cable constructions.

Other components are less dependent on external conditions, or, like it is the case for circuit ends, environmental conditions (e.g. weather) are reflected in the specification of the asset itself (open air or closed).

5.2 Electricity-specific environmental factors

In addition to the factors discussed above, a smaller set is proposed in relation with conditions that affect specifically electrical installations, leading to technical choices influencing investments as well as maintenance costs.

- Severe icing conditions that lead to the necessary reinforcement of lines;
- Reduced lines rating ("ampacity") due to high temperatures and high sun radiation, particularly if correlated with low wind speed;
- Winter or summer peak consumption as high load during winter takes advantage of the correlation high load – higher capacity, while summer peak (due to air conditioning load for example) faces high load – lower capacity.

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