

Yardstick and Ex-post Regulation by Norm Model:
Empirical Equivalence, Pricing Effect, and Performance
in Sweden

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Keywords Regulation, incentive, electricity, Sweden

JEL Classification L33, L52, L94

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Yardstick and Ex-Post Regulation by Norm Model: Empirical Equivalence, Pricing Response, and Firm Performance

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Abstract

Following the liberalisation of network industries there has been a number of innovations in incentive regulation. This paper examines the effects of the application of norm models within an ex-post incentive regulation of electricity distribution networks in Sweden. We first examine the empirical equivalence of norm models to real utilities. Next, we estimate the effect of regulation on pricing behaviour and performance of utilities in average costs, quality of service, and network energy losses. The norm models seem to reflect the main network features, demand characteristics, and capital stocks of real utilities. However, the price of labour faced by the utilities affects relative performance insofar as utilities serving rural areas, where labour cost is generally lower will be disfavoured. Also, quality of service has not affected the relative performance of utilities, indicating that incentives may be weak. Moreover, on the whole, utilities respond to norm models and incentives and reduce their average prices. However, investor-owned utilities that perform better than their norm models behave strategically and increase their prices. We also find that investor-owned utilities reduce (inflate) their average cost if they perform worse (better) than the benchmark. Public utilities have not adjusted their costs significantly in response to the incentives. We do not find evidence of improvement in quality of service and reduction in network energy losses although less efficient investor-owned networks seem to have improved on both fronts. Finally, efficient investor-owned utilities seem to have reduced their quality of service in terms of outage length.

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1. Introduction

The history of the search for workable regulatory models and efficient incentive schemes for energy networks dates back to the inception years of the utility industry (Hammond et al, 2002; Schmidt, 2000; House of Commons, 1882). Since the 1980s, privatisation and reform of the infrastructure industries, including that of the electricity sector, has led to a renewed interest in practical incentive regulation for the natural monopoly networks. This search has led to some notable progress and innovations in incentive regulation.

In Europe, notably in the UK and Norway, incentive regulation schemes have been based on the RPI-X price/revenue cap model following Littlechild (1983) and aided by collective frontier-based benchmarking of utilities.¹ In the US, performance based regulation (PBR) has mainly been in the form of price caps or profit sharing schemes and the result of one-to-one agreements between the public utility commissions (PUCs) and individual utilities. In several Latin American countries as well as in Spain and Sweden regulators have used incentive regulation based on engineering-designed reference models or norm models of network utilities as benchmarks.² Incentive regulation using norm models resembles the notion of yardstick competition first presented in Shleifer (1985) where firms are rewarded in relation to their performance against the average cost of a group of comparable firms.

In the regulatory context norm models have been regarded as a means to reduce the information asymmetry between the regulator and the regulated firm. Norm models can be regarded as a bottom-up approach to benchmarking, whereas real firm models of benchmarking using samples of actual firms represent a top-down approach. There is, however, an even deeper methodological difference between the use of norm models versus real firms in incentive regulation and benchmarking that is not readily apparent and is rooted in their disciplinary origins. Conceptually, incentive regulation is rooted in the basic economic principle that, given the right framework and incentives, profit-driven firms produce an efficient outcome. The firm is viewed as a black box and the regulator does not intervene in its internal matters. The use of norm models, however, implicitly assumes that the technologies, organisation, and operations of the firm can be represented by deterministic engineering models. However, in practice, norm models cannot reflect the flexibility, dynamism, synergies, and innovative drive of real firms (Jamasb and Pollitt, 2008).³

¹ See Joskow and Schmalensee (1986) for a review of the main regulation models, Coelli et al. (2005) for detailed discussion of the benchmarking techniques, and Jamasb and Pollitt (2001) for a survey of regulatory benchmarking in the electricity sector.

² In Chile and Peru several norm models are developed for different categories of service areas based on customer density and geography (rural vs. urban) by optimizing one actual firm from each category. In other countries, one norm model is developed for each network based on its specific demand and geographic characteristics.

³ Grifell-Tatje and Lovell (2003) show that in terms of operation and maintenance, the real Spanish electricity distribution utilities were more efficient than their benchmark norm models.

We also note that ownership needs to be accounted for in the context of assessing utility responses to regulatory characteristics. This follows from the suggestions that publicly owned firms suffer from broad and ill-defined objectives, no bankruptcy constraint and an absence of a residual claimant (Blom-Hansen 2003; Savas 1987; Niskanen 1971). Empirical investigations also support the view that public utilities respond less aggressively to financial incentives (Söderberg, 2008a).

This paper examines (i) the extent to which norm models reflect the features of real networks; (ii) the access pricing response of firms; (iii) their cost and quality of service performance; and (iv) the role of ownership type. The next section briefly outlines the regulation of electricity distribution utilities in Sweden. Section 3 discusses the methodology of the analysis. Section 4 presents the data and the results. Section 5 presents the conclusions.

2. Incentive-Based and Ex-Post Regulation in Sweden

In 2003 the Swedish electricity regulator (STEM)⁴ implemented an incentive regulation model for electricity distribution by which the utilities' actual revenues are benchmarked against the cost of its engineering-designed model developed by the network performance assessment model (NPAM). The underlying principles are outlined in the Swedish Electricity Act, (SFS 1997:875), which states that "... network tariffs shall be designed such that the network concessionaire's total income from network-related activities is reasonable with respect to both the objective circumstances of operating the network and the network concessionaire's way of operating the network. Network tariffs shall be based on objective criteria." (Chapter 4, Section 1).⁵ From an economic point of view this implies that all relevant exogenous cost drivers should be accounted for in the calculation of the standard cost. The Act provides further instructions as it outlines that the foundations on which tariffs shall be based are: (i) number of connection points (i.e. number of customers), (ii) geographic co-ordinates of all connection points, (iii) amount of distributed energy, (iv) subscribed power, (v) cost of regional/high voltage network (i.e. the cost of energy transmission from point of production to the local network), and (vi) electricity quality.

The NPAM-based benchmarks are not intended to represent the efficient frontier or best practice but rather 'reasonably' efficient networks. Norm models are used to screen out utilities whose performance in terms of costs and/or access charges is significantly worse than their fictive peers and to subject them to detailed regulatory scrutiny.

⁴ The STEM department with responsibility for regulating the electricity market goes under the name 'The Energy Markets Inspectorate' (EI) since 1 January 2008.

⁵ The quotation from the Act is freely translated from Swedish.

The aim is to obtain, for each utility, a “charge grade” as the ratio of the actual firm’s revenue over the costs of a norm model (denoted ‘standard cost’ by EI) obtained from the NPAM. A charging grade lower than unity indicates that the firm is more efficient than its norm model while firms with charge grades significantly higher than unity can be subjected to detailed regulatory scrutiny and investigation. In practice, some actual utilities perform worse than their norm models and others have done better than their benchmark. The methodology and main steps of developing the NPAM reference models are shown in Appendix 1.

Another feature of the Swedish regulatory model is the adoption of ex-post regulation. Finland is the only other case in Europe where this type of regulation is implemented. In an assessment of the Swedish approach to network regulation, Jamasb and Pollitt (2008) discuss how ex-ante regulatory contracts are relatively more predictable while ex-post regulation combined with annual rate reviews as practised in Sweden can lead to increased uncertainty, higher likelihood of renegotiations, and reduced incentives for innovation. In Sweden, the regulator also indicated that the threshold charge grade triggering regulatory investigation would be tightened in subsequent years.⁶ The current regulatory approach has been contested by a number of utilities. As a consequence, EI intends to adopt ex-ante regulation from 2012, though it will continue to assess the utilities’ performance in relation to standard costs based on “reasonably” efficient investment and operational practice (SOU, 2007).⁷

Ex-post regulation can influence the incentives and behaviour of firms ex ante. For example, ex-post regulation can increase the possibility of opportunistic behaviour by the regulator. Firms can internalize this possibility and alter their response accordingly. If firms believe that the regulator will use their observed costs to adjust future prices ex-post or discover that their revenues are below the trigger level, in particular at the start of a new regulatory regime, they may increase prices and/or even their costs ex-ante to continue to earn rents in the future (See Joskow, 2007 and Armstrong and Sappington, 2005 for related theoretical discussion).

3. Methodology and Data

It is instrumental that cost-based benchmarks fully account for network heterogeneity, or else they will suffer from the ‘omitted variable bias’. This has indeed turned out to be a feature of norm models elsewhere, and particularly the neglect of firm-level information on input prices and demand, which makes efficiency estimations unreliable (Vogelsang, 2002). Previous investigations (e.g. Burns and Weyman-Jones 1996; Filippini and Wild 2001 and Berg et al. 2005) suggests that the following factors can be regarded as exogenously determined cost

⁶ The threshold values for detailed regulatory investigations have varied according to: 1.3 in 2003, 1.2 in 2004, 1.2 in 2005 and 1.1 in 2006.

⁷ A “reasonably” efficiency cost should be understood as an average cost in this context (SOU, 2007, p.19).

drivers in local electricity distribution:⁸ (i) maximum demand on the system, (ii) total number of customers served, (iii) type of customer, (iv) dispersion of the customers, (v) size of the distribution network (interpreted as distribution area), (vi) value placed upon system security, (vii) ground characteristics, and (viii) climate. In addition, a cost function must also include a representation of the underlying production (input-output) system. While NPAM attempts to include several of these cost-drivers,⁹ the literature seems to argue that there might be factors that are unaccounted for and hence, there is a risk that the charge grade calculations are misleading. Similar problems are also discussed by Bustos and Galetovic (2004, p.21) regarding the case of the Chilean norm model regulation of electricity distribution networks although they only address customer density as an exogenous cost factor. While the Government Commission on future electricity regulation (SOU, 2007) in Sweden appreciates that all exogenous costs should be accounted for it does not specify guidelines on which factors are to be regarded as exogenously determined.

Following Farsi et al (2006) we assume that electricity distribution has one output (kWh delivered, Q) and three inputs (price of capital, labour and electricity). While recent studies often consider a multi-output system consisting of kWh delivered and number of customers (e.g. Goto and Tsutsui, 2008; Cronin and Motluk, 2007), we note that this output distinction is a mere linguistic issue in our case as number of customers is included in the network heterogeneity list above and the subsequent econometric specification is indifferent as to whether number of customers is included in that list or considered as an output.

We define price of capital as capital expenditure divided by total operational assets where capital expenditure is calculated as the sum of depreciation and interest. Operational assets are used as a proxy for the stock of capital since inventory data is not available and, as pointed out by Aubert and Reynaud (2005), any capacity measure would not reflect the total capacity or depreciation of capital. While similar definitions have been used previously in electricity distribution (e.g. Nemoto and Goto, 2006), we note that equity expenses are not included since they are not reported by utilities. This could distort the cost measure if owners' rate of return is time-variant and/or if networks are subject to expansion or termination. However, it has been concluded by STEM/EI that the variation in WACC is primarily due to interest variation which is included in our measure. Since depreciations are based on accountancy principles which generally deviate from market-based principles, a further source of bias can be introduced but this impact is assumed to be negligible since our relatively large panel reduces the impact from temporary behaviour.

Price of labour is average monthly salaries, net taxes, on a county level as reported by Statistics Sweden. Average population labour statistics are regarded as superior to those

⁸ A few additional factors have appeared in the literature, e.g. length of distribution line, overhead/underground network mix, transformer capacity, network energy losses (see e.g. Short et al., 2003; Hirschhausen et al., 2006), but these are, at least partly, endogenous to the utilities and not included here. E.g. we show further below that losses are determined by delivered amount of electricity, customer density and the load factor.

⁹ See Appendix A for additional details.

reported by utilities since the utilities' statistics tend to have unreasonably high variability and a large proportion of missing values.¹⁰ The price of electricity is included because utilities need to purchase electricity to cover network losses and pay for transit on the high voltage network. The price is calculated as the total cost of transit and losses divided by the sum of losses and high voltage deliveries.

Maximum demand on the system is measured as the average load factor (ratio of electricity delivered over total capacity, *Load*) and we expect increased network utilisation to be associated with lower average cost. Type of customer is included as share of electricity delivered on the low voltage network (*ShLowV*) and average customer consumption (*AvgCon*). Share of electricity delivered is ambiguously related to average cost since low voltage customers require additional transformation technology and high voltage customers have less pronounced daily and seasonal demand peaks, which increases network utilisation. These two effects predict that a higher share of low voltage electricity increases average cost. However, high voltage deliveries are associated with a transit cost and the net effect is, therefore, left to the empirical investigation.

Higher average customer consumption is associated with lower average cost because the fixed customer specific cost is divided by a larger amount of electricity. Dispersion of customers is measured as customer density (*Dens*) (number of customers over concession area) and because density generates coordination benefits, higher density is expected to lower costs. Concession area is excluded to avoid perfect multicollinearity and we argue that line length, although used occasionally (e.g. Hirschhausen et al., 2006; Berg et al., 2005), is an unsuitable substitute as it could hide rent.

Network quality is accounted for through average outage frequency (*OutFreq*) (number of outages over number of customers) and average outage time (*OutTime*) (total outage time over number of outages). A further quality indicator is network losses (*Loss*) and although not directly visible to the customers, it inflates costs as it has to be compensated for through increased energy input. Neither ground characteristics nor climate variables are available for the time period considered in this study. However, we do not believe that that is a serious limitation since Söderberg (2008a) only found a negligible to weak impact on cost from these factors in his estimations of various cost functions for the same utilities covering a shorter time period.

When specifying the functional forms of charge grade (*CG*), average price (*AvgP*) and average cost (*AvgC*) we choose a quadratic form although the translog form is more frequently adopted in the literature. The rationale for this is threefold (Kwoka, 2005): (i) the

¹⁰ The problem with labour statistics reported by utilities is due to non-perfect reporting of labour resources being shared among several utility and/or local government services.

quadratic form handles many fixed terms more readily, (ii) it does not rest on the profit-maximising assumption (which is likely to be overly restrictive for publicly owned utilities) like the translog form, and (iii) the quadratic form has been found to generally out-perform most other forms, including the translog (Färe et al., 2006; Shaffer, 1998). One conclusion drawn is that the translog form tends to suggest U-shaped average cost curves even when average cost is in fact L-shaped (i.e. strictly declining). This can have important implications for modelling network industries where the average cost is commonly believed to be L-shaped.

Assuming a third degree polynomial approximation of output for the total cost function (see Kwoka, 2005 for further details), CG can be formulated econometrically as:

$$\begin{aligned}
 CG'_{it} = & \alpha_0 + \alpha_1 AvgP_{it} + \alpha_2 Cust_{it} + \alpha_3 ShLowV_{it} + \alpha_4 ACon_{it} + \alpha_5 Dens_{it} + \alpha_6 Q_{it}^{-1} + \\
 & \alpha_7 Q_{it} + \alpha_8 Q_{it}^2 + \alpha_9 Load_{it} + \alpha_{10} Plab_{it} + \alpha_{11} Pele_{it} + \alpha_{12} Pcap_{it} + \alpha_{13} OutFreq_{it} + \\
 & \alpha_{14} OutTime_{it} + u_{1i} + \varepsilon_{1it}
 \end{aligned} \tag{1}$$

where CG' indicates that CG has been rescaled by a factor 100 to better balance coefficient values in subsequent estimations; i is utility and t year; u_i is the panel effect and ε_{it} the random error term.

It is reasonable to assume that pricing is endogenous in eq (1) and determined by the same factors as cost with the mark-up assumed to be constant over time and primarily captured by the firm-specific intercept (the panel effect).¹¹ Price will also be affected by the 2-period charge grade lag since charge grades based on data from year t are published during the second half of year $t+1$ which allow utilities to incorporate that information while setting prices for year $t+2$.¹²

With the assumption that $CG' = 100$ creates no price or cost adjusting incentives, CG' is transformed again according to $CG'' = (100 - CG')$ which has the effect of making $CG'' = 0$ equivalent to $CG = 1.0$. Since CG was not calculated until 2003 this also allow us to include hypothetical CG 's for the 2000-2002 period where CG'' takes the value 0 for all utilities during 2000-2002. This has the advantage of allowing us to include data before the NPAM was introduced. The dummy variable IO is included to measure the difference in response from investor-owned and publicly owned utilities. Hence, average price is assumed to fit the function:

¹¹ Romilly (2001) argues that monopolies primarily set prices to cover costs and Hall et al. (1997) argue that even firms in competitive markets regularly use cost-plus pricing.

¹² CG'' -terms are excluded from eq (1) to allow for some unique instruments in eq (2).

$$\begin{aligned}
AvgP_{it} = & \beta_0 + \beta_1 Cust_{it} + \beta_2 ShLowV_{it} + \beta_3 ACon_{it} + \beta_4 Dens_{it} + \beta_5 Q_{it}^{-1} + \\
& \beta_6 Q_{it} + \beta_7 Q_{it}^2 + \beta_8 Load_{it} + \beta_9 Plab_{it} + \beta_{10} Pele_{it} + \beta_{11} Pcap_{it} + \\
& \beta_{12} OutFreq_{it} + \beta_{13} OutTime_{it} + \beta_{14} T_t + \beta_{15} CG''_{it-2} + \beta_{16} CG''_{it-2} \cdot B_{it} + \\
& \beta_{17} IO \cdot CG''_{it-2} + \beta_{18} IO \cdot CG''_{it-2} \cdot B + u_{2i} + \varepsilon_{2it}
\end{aligned} \tag{2}$$

B is introduced to represent the interaction effect with two of the CG'' -terms. B takes the value 1 when $CG' < 100$ (i.e. the actual utility performs better than its norm model). Thus, B allows us to separately investigate utilities' response when CG is less and greater than 100 and IO serves the same purpose for ownership. As outlined earlier, the average cost function mirrors that of the average price function:

$$\begin{aligned}
AvgC_{it} = & \chi_0 + \chi_1 Cust_{it} + \chi_2 ShLowV_{it} + \chi_3 ACon_{it} + \chi_4 Dens_{it} + \chi_5 Q_{it}^{-1} + \\
& \chi_6 Q_{it} + \chi_7 Q_{it}^2 + \chi_8 Load_{it} + \chi_9 Plab_{it} + \chi_{10} Pele_{it} + \chi_{11} Pcap_{it} + \\
& \chi_{12} OutFreq_{it} + \chi_{13} OutTime_{it} + \chi_{14} T_t + \chi_{15} CG''_{it-2} + \chi_{16} CG''_{it-2} \cdot B_{it} + \\
& \chi_{17} IO \cdot CG''_{it-2} + \chi_{18} IO \cdot CG''_{it-2} \cdot B + u_{3i} + \varepsilon_{3it}
\end{aligned} \tag{3}$$

We now turn to the relationship between NPAM and quality of service. Broadly, service quality can be measured in terms of outages as well as network energy losses. Contrary to utility cost and price investigation, there is a notable absence in the literature on which factors influence quality. Considering the difficulties associated with pre-specification of quality in contracts, with its consequent risk of utilities reducing quality as a way to lower costs, one would expect diverting quality levels among investor-owned profit-maximising and public utilities. This would be a particular relevant to consider when cost-reducing regulatory incentives are used. Apart from ownership and regulation, practical experience predicts that outages are influenced by customer density (density is positively related to a customer experiencing an outage given constant probability of technical fault), climate and proximity between overhead lines and trees. A previous analysis of outages in Sweden revealed that only density, extreme storms, and a trend could significantly predict outage minutes (Söderberg, 2008b).

We use the above variables affecting outages in our analysis and add the 2-period lag of CG'' , $CG'' \cdot B$, $IO \cdot CG''$ and $IO \cdot CG'' \cdot B$ to our outage model. A linear functional form in level is applied which we formulate as:

$$\begin{aligned}
Outage_{it} = & \delta_0 + \delta_1 Dens_{it} + \delta_2 Y05_{it} + \delta_3 T_t + \delta_4 IO_{it} + \delta_5 CG''_{it-2} + \\
& \delta_6 CG''_{it-2} \cdot B_{it-2} + \delta_7 IO \cdot CG''_{it-2} + \delta_8 IO \cdot CG''_{it-2} \cdot B_{it-2} + u_{4i} + \varepsilon_{4it}
\end{aligned} \tag{4}$$

where $Y05$ is dummy for year 2005 when large parts of Sweden experienced an unusually severe storm.

The amount of network energy losses is assumed to be determined by amount of electricity delivered, density, load and share of low voltage deliveries. Following the arguments above, ownership and financial incentives are also included to capture the negative relationship between cost and quality. While it is clear that large quantities are associated with relatively larger losses, remaining variables are hypothesised to capture network congestion and technical characteristics of losses (e.g. high voltage deliveries are associated with less losses). Thus, we formulate the loss function as:

$$Loss_{it} = \gamma_0 + \gamma_1 Q_{it} + \gamma_2 Dens_{it} + \gamma_3 T_t + \gamma_4 Load_{it} + \gamma_5 ShLowV_{it} + \gamma_6 CG''_{it-2} + \gamma_7 CG''_{it-2} \cdot B_{it-2} + \gamma_8 IO \cdot CG''_{it-2} + \gamma_9 IO \cdot CG''_{it-2} \cdot B_{it-2} + u_{5i} + \varepsilon_{5it} \quad (5)$$

Data

Table 1: Descriptive statistics

Variable	Description and measurement unit	n ^a	Mean	Std.dev.	Min	Max
<i>CG'</i>	Charge grade · 100	657	106.62	16.31	50.3	179.1
<i>CG''</i>	100 - Charge grade · 100	1152	-3.7758	12.7458	-79.1	49.7
<i>AvgP</i>	Average price (SEK/kWh)	1243	0.2030	0.0532	0.0617	0.3898
<i>AvgC</i>	Average cost (SEK/kWh)	1243	0.1707	0.0497	0.0743	0.3748
<i>Cust</i>	Number of customers	1278	20 163.10	42 118.47	518	459 668
<i>ShLowV</i>	Share of electricity delivered on low voltage network	1278	0.7598	0.1634	0.163	1.000
<i>AvgCon</i>	Average customer consumption (kWh)	1278	20 544.96	7 719.42	4 423.08	83 839.46
<i>Dens</i>	Customer density	1278	97.2342	197.0187	0.3232	2 124.41
<i>Q</i>	Electricity delivered (GWh)	1278	404.82	740.29	2.3	7 472.72
<i>Loss</i>	Network losses (MWh)	1268	16 829	29 793	300	341 181
<i>Load</i>	Load factor	1261	0.4958	0.0796	0.1369	0.9039
<i>Pele</i>	Price of electricity (SEK/kWh)	1013	0.3236	0.2318	0.0958	1.1897
<i>Pcap</i>	Price of capital (SEK)	1248	0.0982	0.0469	0.0228	0.5731
<i>Plab</i>	Price of labour (SEK)	1311	18 609	907	16 900	20 913
<i>OutFreq</i>	Number of outages per customer	1275	1.0406	1.9912	0	58.39
<i>OutTime</i>	Average outage time (min)	1276	113.31	310.7642	0	5667
<i>IO</i>	Dummy var to indicate that concession is investor-owned	1313	0.1592	0.3660	0	1
<i>Outage</i>	OutFreq · OutTime (min)	1276	269.9064	1 458.92	0	36 143

^a *CG'* covers the 2003-06 period. Remaining variables cover the 2000-07 period.

Sources: STEM/EI (www.ei.se) for all but *Plab* which was collected from SCB (www.scb.se).

The data used in this study represents the local area electricity distribution concession-holders in Sweden covering the 2000-2007 period. A concession-holder is synonymous to a utility apart from the largest utilities which operate several concessions. Due to mergers and acquisitions the number of concessions have decreased markedly during this period from well above 200 at the beginning of the 2000s to 177 in 2007. Because of some missing data and the exclusion of some extreme values, the data set used consists of an unbalanced panel of 164 concessions. There is no sign of structural exclusion. Descriptive statistics are provided in [Table 1](#).

4. Results

This section presents the analysis of some aspects of the application of norm models in ex-post incentive regulation of electricity distribution networks in Sweden. We first examine the extent to which the theoretical norm models have, on the whole, been empirical equivalents of the real networks. We then analyse the utilities' pricing behaviour and performance effects of the regulatory approach. Eqs (1)-(3) are estimated with fixed panel effects since the Hausman specification tests suggest that random effects are biased (test statistics are provided in [Table 2](#)).

a. Empirical equivalence of norm models

As discussed, charge grades are the ratio of the utilities' prices/revenues and their standard cost calculated from their norm model. As benchmarks, the standard costs should reflect the main features and cost drivers of real networks. The analysis below examines the extent to which these factors have affected the real firms' charge grades. [Table 2](#) shows the results of regression analysis with the utilities' charging grades as the dependent variable.

We use distribution network prices as a control variable. For other variables, to the extent that norm models are true representations of real firms, the technical, demand, and economic features of real networks should no longer have a significant effect on the charge grades. As expected, we find that the level of network prices is positively and significantly correlated with the charge grades – i.e. networks with higher prices tend to have higher revenues and hence higher *CG*'. Also consistent with expectations, factors such as number of customers, customer density and load which are explicitly built into the norm models do not show a significant effect on *CG*'s.

Table 2: Empirical equivalence of norm models and the influence of charge grades on average price and average cost

Variables	Dep. variable: Charge grade Eq (1)		Dep. variable: Average price Eq (2)		Dep variable: Average cost Eq (3)	
	Coeff.	Robust std. err.	Coeff.	Robust std. err.	Coeff.	Robust std. err.
AvgP	559.3***	40.58				
Cust	1.8·10 ⁻⁵	8.4·10 ⁻⁴	-9.26·10 ⁻⁷	1.00·10 ⁻⁶	4.40·10 ⁻⁷	1.14·10 ⁻⁶
ShLowV	20.91	15.45	0.0331**	0.0189	-0.0506**	0.0237
AvgCon	0.0041***	9.9·10 ⁻⁴	-1.36·10 ⁻⁶ **	5.78·10 ⁻⁷	-1.30·10 ⁻⁶	9.39·10 ⁻⁷
Dens	-0.0807	0.1255	5.62·10 ⁻⁴ ***	1.44·10 ⁻⁴	1.77·10 ⁻⁴	1.36·10 ⁻⁴
Q ⁻¹	-658.7	635.8	4.2180***	0.8395	4.3716***	1.0207
Q	-0.0446	0.0462	-1.92·10 ⁻⁴ ***	3.65·10 ⁻⁵	-1.47·10 ⁻⁴ **	5.06·10 ⁻⁵
Q ²	2.92·10 ⁻⁷	5.43·10 ⁻⁶	2.30·10 ⁻⁸ ***	4.77·10 ⁻⁹	1.40·10 ⁻⁸ *	8.19·10 ⁻⁹
Load	-10.47	23.30	-0.0204	0.0167	-0.0161	0.0193
Pele	-10.97*	5.945	0.0119**	0.0086	0.0427***	0.0099
Pcap	27.17	20.99	0.0433**	0.0197	0.1170***	0.0295
Plab	-0.0083***	9.0·10 ⁻⁴	1.46·10 ⁻⁵ ***	1.52·10 ⁻⁶	8.93·10 ⁻⁶ ***	2.37·10 ⁻⁶
OutFreq	0.1475	0.0911	-7.25·10 ⁻⁵	1.15·10 ⁻⁴	-4.38·10 ⁻⁴ **	2.23·10 ⁻⁴
OutTime	0.0014	0.0016	2.77·10 ⁻⁶ *	1.55·10 ⁻⁶	2.43·10 ⁻⁵ ***	8.38·10 ⁻⁶
T			-0.0046***	5.68·10 ⁻⁴	-0.0016*	8.84·10 ⁻⁴
L2_CG			2.51·10 ⁻⁴ ***	4.21·10 ⁻⁵	1.01·10 ⁻⁴	7.10·10 ⁻⁵
L2_CG·B			-2.71·10 ⁻⁴ **	1.48·10 ⁻⁴	-3.29·10 ⁻⁴ *	1.77·10 ⁻⁴
IO-L2_CG			1.26·10 ⁻⁵	6.13·10 ⁻⁵	2.79·10 ⁻⁴ ***	1.22·10 ⁻⁴
IO-L2_CG·B			5.67·10 ⁻⁴ ***	2.30·10 ⁻⁴	2.63·10 ⁻⁷	5.39·10 ⁻⁴
Constant	107.5***	38.80	-0.0888**	0.0382	0.0455	0.0538
Hausman spec test statistic (χ^2)	67.51 ^a		34.16 ^a		34.22 ^a	
R ² (within)	0.64		0.46		0.39	
R ² (overall)	0.02		0.09		0.29	
n	525		765		765	

* $p < 0.10$, ** $p < 0.05$, *** $p < 0.01$
^a Significantly different from 0.

However, three additional variables seem to have a significant impact on CG' and two of these ($AvgCon$ and $Plab$) are significant on the 1 % level. To illustrate the sensitivity of these two we calculate the elasticities at their mean values and find that $AvgCon$ and $Plab$ have elasticities of 0.767 and -1.480 respectively. A 10 % increase of the sample mean for $AvgCon$ therefore increases the average CG' -value from 106.6 to 114.8 and an equivalent increase of $Plab$ reduces CG' to 90.8. Relatively modest changes in these variables therefore have significant impacts on the probability of whether a utility will be subjected to a costly and time consuming regulatory investigation.

The results indicate that the NPAM generally captures the main network characteristics, demand features, and stock of capital. However, both price of labour and electricity, as major inputs in operating expenditures, can affect the utilities' CG . This can have an adverse effect

on utilities that, for example, serve rural areas which generally face a lower labour cost. Moreover, we observe that the quality of service indicators have no effect on charge grades. We would expect the regulator to have built in stronger incentives for quality improvements. While both outage frequency and average outage time have positive signs none is significant at the 10% level. As a result service quality may not improve in response to regulation using norm models. We address this question in our subsequent results.

b. Determinants of average network price

The results from the estimation of eq. (2) show that utilities with higher low-voltage customers, density, input prices and outage time have higher prices. Moreover, utilities with higher average consumption tend to have lower prices. As expected, all utilities with a charge grade above 100, faced by the threat of regulatory investigation, reduce their average prices. In addition, investor owned utilities with a charge grade below 100, as expected from the principle of profit-maximisation, increase their average prices (Figure 1).

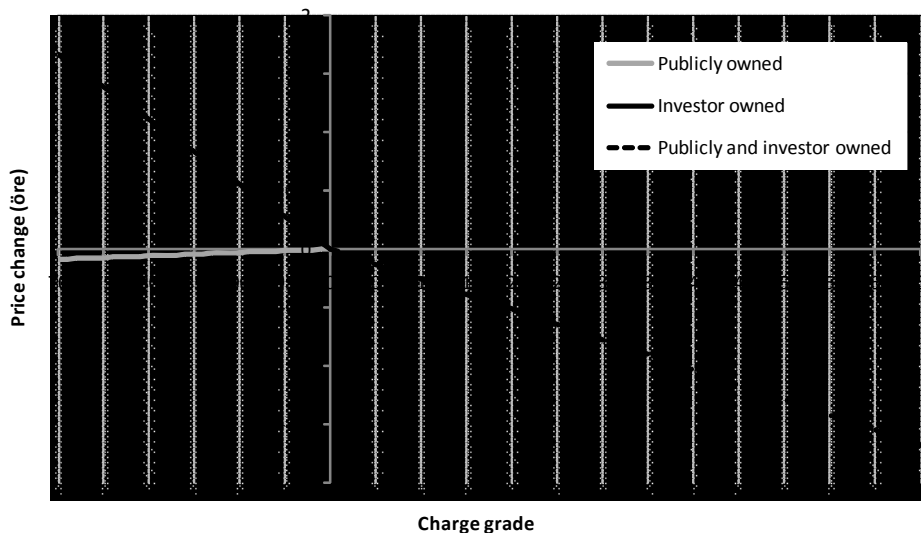


Figure 1: Price change vs. charge grade

The latter result is in line with the finding of Growitsch and Wein (2005) that following the publication of distribution charges in Germany, and anticipating future incentive regulation, low-price utilities increased their prices while high-price utilities reduced their prices. However, our results show that publicly (mainly municipally) owned utilities do not seem to behave the same way which lends some support to the public interest view that publicly owned firms do not (primarily) follow a profit-maximising objective.

c. The effect of regulation on average costs

The introduction of new regulation has also had an effect on the utilities' actual costs. Note that the costs are different from the standard cost stipulated by the norm models. Again we examine firm specific factors and quality of service performance as well as ownership type on average costs. The results indicate that share of low voltage deliveries and total deliveries are negatively and significantly correlated with average costs. As expected, high input prices increase the cost level.

The effect of quality of service on cost level is mixed. While length of power outages are positively and significantly correlated with average costs the opposite is the case for the frequency of interruptions. This illustrates the technical and regulatory circumstances as utilities are penalised only for outage times above 12 hours. Evidence from the UK and Norway shows that, although using different approaches to regulation, utilities have responded to quality of service incentives while the non-incentivised aspects of reliability have not necessarily improved (CPB, 2004).

We find further evidence that investor owned utilities react more strongly to financial incentives (there is in fact no evidence at the 5 % significance level that publicly owned utilities adjust their costs in response to incentives). As the results show, investor owned utilities with a charge grade above 100 reduce their average cost level to compensate for required price reductions (Figure 2). On the other hand, they also increase their costs (though statistically insignificant) when their charge grades are below 100.

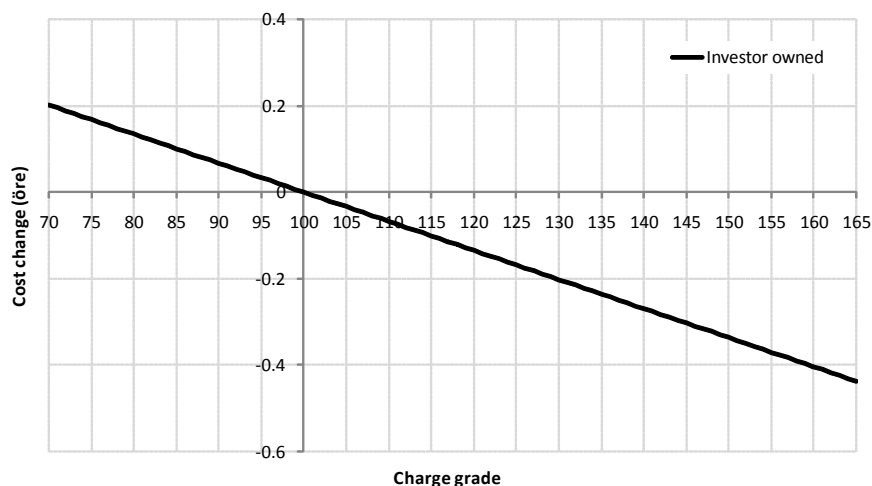


Figure 2: Average cost change vs. charge grade

d. Effect of regulation on average customer outage time and network energy losses

In addition to cost performance, quality of service in electricity networks is, due to its socio-economic importance, a major performance criteria and regulatory focus. We examine the effect of a set of utility features on the length of service interruptions an average customer is exposed to. The Hausman specification test reveals that the random effects specification is unbiased for eq (4) – but not for eq (5) – and we therefore include the time-invariant *IO* dummy variable in eq (4).

Table 3: The influence of charge grade on outages and network losses

Variable	Dep. variable: Customer outage length Eq (4)		Dep. variable: Energy losses Eq (5)	
	Coeff.	Std. err.	Coeff.	Std. err.
Q			79.736 ***	10.100
Dens	-0.6622 ***	0.2556	145.50 **	65.951
Y05	344.31 ***	79.935		
T	-4.6937	20.426	-203.46	135.87
Load			-14058 **	6125.7
ShLowV			8790.5	6312.0
IO	747.56 ***	146.12		
L2_CG	-2.3495	4.0240	13.361	22.374
L2_CG-B	17.589	11.015	-34.026	63.281
IO-L2_CG	11.588 *	5.9437	145.57 ***	35.838
IO-L2_CG-B	23.008 *	13.600	-123.16	82.940
Constant	155.12	100.89	-26630 ***	9087.1
Hausman spec test statistic (χ^2)	10.86 ^a		129.32 ^b	
R ² (within)	0.03		0.12	
R ² (overall)	0.11		0.79	
n	969		949	
* $p < 0.10$, ** $p < 0.05$, *** $p < 0.01$				
^a Not significantly different from 0.				
^b Significantly different from 0.				

As shown (Table 3) customer density has a negative and significant effect on the length of outages whereas the major storm in 2005 increases outage times. Investor-owned utilities have a significantly higher outage time on average and they also, consistent with the pattern found for average cost, adjust their outages in response to the charge grade. It is noteworthy that investor owned utilities tend to increase their outage times if they have a charge grade below 100 (Figure 3).

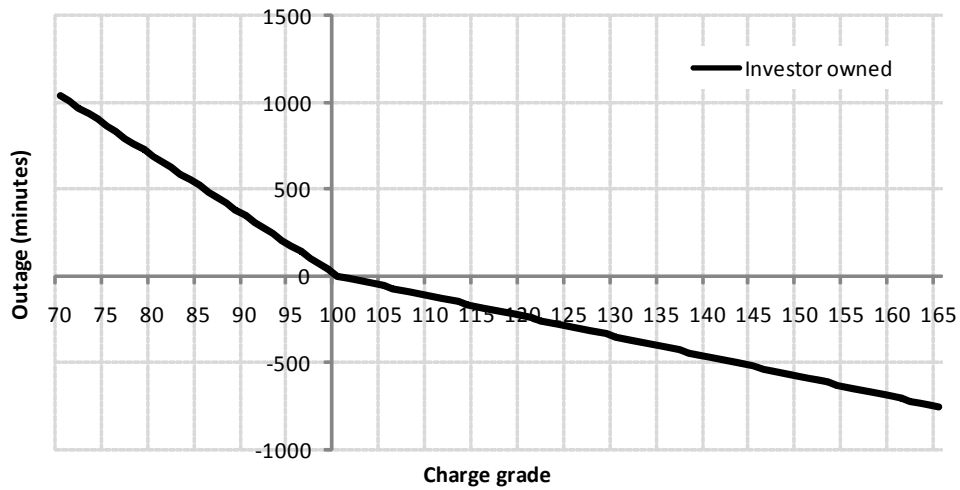


Figure 3: Average outage time vs. charge grade

Network energy losses are accounted for in the norm models and are hence incorporated in the incentive schemes. As expected, the level of energy losses is positively correlated with the amount of energy delivered ([Table 3](#)). Energy losses are also positively correlated with customer density and negatively correlated with maximum network load. With regards to the effect of ownership, network losses are affected in much the same way as the customer outage time – i.e. only investor owned utilities seem to respond to the regulatory incentives and the utilities that have charge grades higher (lower) than 100 tend to reduce (increase) their energy losses ([Figure 4](#)).

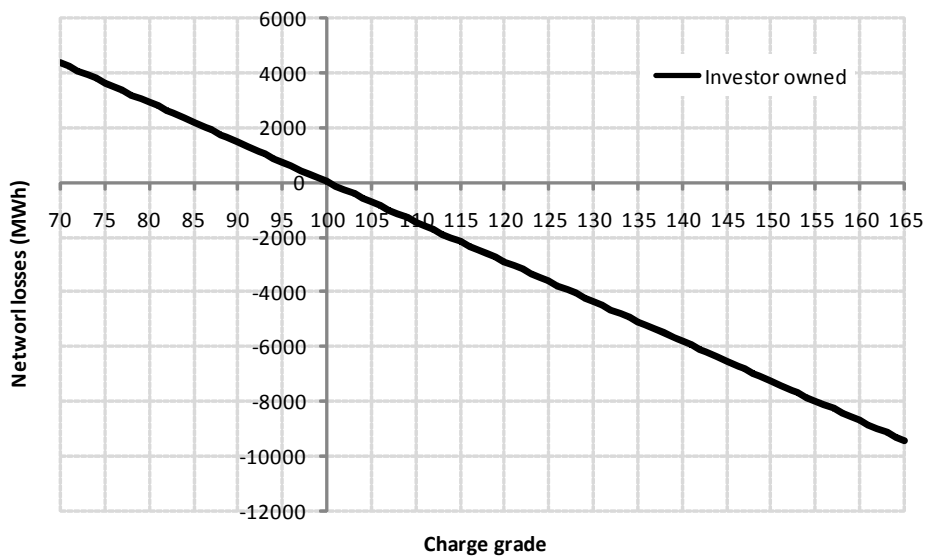


Figure 4: Average outage time vs. charge grade

5. Conclusions

In this paper we present the results of an analysis of various aspects of the regulation of electricity distribution utilities in Sweden. The incentive regulation implemented from 2003 is based on the use of norm models in an ex-post context. We examined the empirical equivalence of the norm models in relation to real utilities. We also estimated the effect of the new regulatory regime on the pricing behaviour of utilities and their performance in terms of average costs, quality of service, and network energy losses.

The results indicate that the norm models to a large extent reflect the main network features, demand characteristics, and capital stocks of the real utilities. However, three of the exogenous cost factors have a significant effect on the charge grade and the price of labour appears to be a major determinant in the decision to initiate detailed investigations. This tends to disfavour the smaller utilities serving rural areas with lower than average labour costs. Also, quality of service indicators do not seem to have influenced the charge grades, indicating that the incentives to improve quality are weak.

The problem of benchmarking against a reasonably efficient utility (the standard cost) is evident from these results. On the whole, utilities with charge grades higher than 100 seem to have reduced their average prices. However, private utilities that perform better than their norm model benchmarks (in terms of charge grades) raise their prices, without risking regulatory intervention, to increase profit and/or increase operational slack. Clearly, the strategic response of these utilities has welfare reducing effects. In addition, we find that investor-owned utilities with a charge grade above 100 reduce costs but that they increase costs if the charge grade is below 100. There is no significant evidence (at the 5 % level) that public utilities change their costs in response to NPAM.

Consequently, we conclude that investor owned and publicly owned utilities have responded differently to the given incentives. In accordance with theoretical expectations, investor-owned utilities have responded more aggressively to incentives both in terms of price increases as well as in the form of cost reductions/increases.

We do not find evidence of improvement in quality of service and reduction in network energy losses. This perhaps reflects the lack of adequately strong incentives that we discussed earlier. Customer density reduces the average length of outages while the 2005 storm had a marked negative effect on them. As in the case of average prices and costs, we find that investor-owned utilities with charge grades over 100 reduce their outages and vice versa. Finally, we find that network energy losses tend to increase with customer density and decline with load factor and that investor-owned utilities show statistically significant reductions in their energy losses.

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Appendix A:

The main steps in developing reference networks using the NPAM

- i. Information on the geographic co-ordinates of all customers for each network company is obtained.
- ii. Information is collected on customers: numbers, energy, and power.
- iii. The model creates a reference network based on technical and legal requirements and with high service quality standards.
- iv. Using the reference network NPAM derives an installation register for:
 - Meters of line per bleeding point
 - A density measure to every meter of line
 - Number of transformer stations
 - Capacity for every transformer station
 - A density measure for every transformer
- v. The model then calculates the investment cost of a reference firm based on standard costs of equipment from the Swedish Electricity Building Rationalisation (EBR) catalogue.
- vi. Costs of building and operating an efficient network today and related costs are derived from a number of cost functions for:
 - Capital expenditures (real cost of capital) - compensation for depreciation, equity, debt (risk free and risk premium)
 - Cost of operation and maintenance
 - Network administration costs
 - Cost of network losses
 - Financial costs
 - Return on capital
- vii. Deductions from revenues are made for quality of service using supply interruptions data of actual companies and customer willingness-to-pay (WTP) values.
- viii. Costs of the reference network are compared against the revenues of the actual network using a charge grade “debiteringsgrad” (ratio of the revenue of the actual network over the costs of the reference network) to obtain a performance measure of the real network.
- ix. The benchmarking exercise is to take place every year *ex-post* and relative to the previous year. Firms with charge grades exceeding unity by a certain margin can be subject to detailed investigation and efficiency requirements by the regulator.

Box A.1: Source: Jamasb and Pollitt (2008)