Economies of scale and (the lack of) consolidations in the Swedish electricity distribution market

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Highlights

- Economies of scales are expected in natural monopoly markets.
- The standard "return to scale at the sample average" approach is incomplete.
- A more extensive approach to investigate economics of scale is presented.
- We apply this new approach to the Swedish electricity distribution market.
- Results suggest that small DSOs could lower their cost substantially.

Abstract

The Swedish electricity distribution system operators (DSOs) vary considerably in size, suggesting that the smallest networks may not exploit their scale advantages. We develop a three-stage analytical approach that is both broader and deeper than the standard "return to scale at the sample average" approach. In the first stage, the smallest and largest DSOs are tracked over the last 15 years at firm level. Despite large size differences, there have been relatively few mergers and acquisitions that involve the smallest DSOs – only about one every two years. In the second stage, we perform an econometric investigation with data from 177 DSOs over 14 years. This investigation shows that a majority of DSOs could lower their average cost substantially by merging into larger units; if number of customers increase by 10%, the smallest DSOs will lower their average cost by 10-15%. In the third stage, a questionnaire is sent out to all DSOs, asking them about their most recent attempts to consolidate and their reasons for (not) engaging in such activities. The results reveal that many DSOs do not think the gains are large enough relative to the costs associated with a complicated/risky consolidation process. A natural policy recommendation is to adjust the regulatory approach so that small DSOs can keep some of the gains that are realized when they merge – for example by calculating the revenue cap in the post-consolidation regulatory period based on the pre-consolidation cost level.

1. Introduction

It is widely accepted that electricity distribution system operators (DSOs) are natural monopolies, i.e., that their average cost is strictly falling as a function of delivered electricity, number of customers and other measures that represent the quantity of their business activities. A substantial empirical literature, using data from several different countries, supports this proposition, e.g., Giles and Wyatt (1993) for New Zealand, Filippini (1996) for Switzerland, Burns and Weyman-Jones (1996) for England and Wales, Kwoka (2005) for the U.S. and Kumbhakar et al. (2015) for Norway. When services have natural monopoly characteristics, the expectation is to observe few local markets, where each market is served by one supplier. According to the review by Hanley and Pollitt (2009), that is also the case in many countries, such as in Australia, Croatia, Great Britain, Greece, Hungary, Ireland, Lithuania, Netherlands, Portugal, and most of the Latin American countries. However, some countries stand out as having relatively many DSOs, e.g., Austria, Germany, and the Nordic countries. Why is it that these countries have not exploited the economies of scale in local electricity distribution to the same extent? Is it that the technologies used in these countries have smaller scale advantages? Are the regulatory incentives for mergers and acquisitions weaker, e.g., does the regulator require the cost reductions to immediately be passed on to consumers? Are there non-financial reasons, e.g., based on ideology (a preference for small and local providers) or an unwillingness to give up influence over firm decisions, that dictate firm structure? It has also been argued that the local community can have an interest in keeping the DSOs small and local since that can benefit the local economies (Kumbhakar et al., 2015). Moreover, what would an appropriate policy response be in these countries? In this paper, we take a detailed look at the Swedish electricity distribution market to investigate if there are unexploited economies of scale there, and if there are, what the appropriate policy response would be.

As a first step, we track which consolidations and divestiture processes the smallest and largest DSOs have been involved in over the last 15 years. Next, we determine the scale properties using various econometric specifications collected from the Swedish energy regulator. This exercise allows us to determine the slope of the average cost curve at different volumes of delivered electricity. These slopes can be interpreted as incentives for consolidation, where a positive slope indicate diseconomies of scale, a slope equal to zero that there are no incentives for consolidations, and a negative slope that there are economies of scale – the more negative, the stronger the incentive for mergers. We then send out a questionnaire to all DSOs and ask whether they engaged in any mergers or acquisitions in 2018 or 2019, or if they have been involved in attempts that did not materialize in any consolidations. We also ask about the reason(s) for those decisions, regardless of whether they resulted in an active or passive stance.

The picture that emerges is that Sweden has a large number of relatively small DSOs that, over the last two decades, have shown limited interest in consolidating into larger units. Nineteen of the 25 smallest firms in 2005 had the same organizational structure in 2017, i.e., they had not merged or initiated formal cooperation with any other firm. This is not due to the lack of scale benefits. We find that both the small- and medium-sized firms can reduce their average cost substantially: if number of customers increase by 20%, the decrease in AC for the smallest firms (2,000 MWh of electricity delivered per year) is approximately 27 percent, and for medium-sized firms (e.g., 200,000 MWh of electricity delivered per year), about 10 percent. The scale effect for a large firm (5,000,000 MWh of electricity delivered per year) is smaller and amounts to around 2%. This suggests that the aggregate cost savings from improving the market structure may be substantial. Indeed, we show that if all firms had the same average cost as the firm with the lowest average cost, the aggregate cost would decrease by approximately 15 percent, and it would only take 110 firms to supply the market.

Given the presence of these possibilities to reduce cost, it is puzzling that not more of the small and medium-sized DSOs have merged with each other. The questionnaire that was sent out generated a response rate above 60%, and the responses reveal that only about 5% had been involved in mergers in the last two years. One DSO started a merger process but terminated it when it became clear that it would not result in a net financial gain. Some additional qualitative responses were also received, and they all suggest that mergers were not sufficiently attractive from a financial point of view. No respondent claimed that the reason for being small was to keep the influence over important financial decisions, e.g., to set prices below, or quality above, what the regulator mandates. A closer look at the regulatory framework reveal that DSOs are required to pass on any cost saving to customers as soon as they become known to the regulator, which typically happens in the following regulatory period. Thus, DSOs have limited incentives to operationalize cost savings and it is little surprise, therefore, that DSOs have not initiated mergers and acquisitions to a greater extent.

These findings lead us to recommend policymakers to implement stronger financial incentives to stimulate mergers involving small DSOs. The regulator can create such incentives in several ways. One way is to calculate the revenue cap for the post-consolidating DSO in the following regulatory period as the sum of the caps in the pre-consolidating period – conditioned on that the DSOs are below a certain size.[1] This will give a temporary financial reward to the consolidated DSOs that is as large as the sum of the scale benefit. The other

[1] The incentives for mergers and acquisitions increases when the caps in the pre-consolidating period is extended to regulatory periods further into the future.

approach is to redesign the regulatory process and permanently award a higher cap-to-cost ratio to medium-sized, and possibly large, DSOs. This can be designed to give a temporary or permanent reward if networks transition from a smaller segment.

Our paper contributes to the existing literature in two ways. First, it identifies the scale properties in the Swedish electricity distribution market. These properties have not been identified since Kumbhakar and Hjalmarsson (1998) published their study more than 20 years ago, and those old results do not necessarily apply today. Second, it develops a general approach to investigate "scale" that goes beyond the standard focus on "return to scale at the sample average" in several ways. This involves the identification of each single ownership transaction, which reveals important drivers behind mergers and acquisitions, for example, that mergers only occur between neighboring DSOs. It also involves the identification of scale elasticities across the size distribution. This reveals the benefits of mergers and acquisitions for different group sizes, and allows policymakers to target interventions only to those groups for whom doing so increases welfare. Finally, the framework involves asking DSOs about the reasons for why they did or did not engage in consolidation attempts. These qualitative responses yield important information to allow policymakers to design appropriate interventions – e.g., whether interventions should focus on creating financial incentives and/or informing about potential scale effects.

The remainder of the paper is structured as follows. Section 2 describes the local electricity distribution market with a focus on the organizational structure of the smallest and largest DSOs in the last 15–20 years. Section 3 describes the data and presents relevant descriptive statistics. Section 4 contains the econometric analyses that form the basis of the scale elasticities. Section 5 presents the questionnaire and the responses from the DSOs. Section 6 concludes the paper.

2. Institutional background

During the 1990s, many European countries, including Sweden, deregulated their electricity markets. The deregulation was aimed mainly at increasing efficiency by creating competition in the production and retail sectors. Consequently, regulations were removed in the wholesale and retail markets, which allowed market participants to trade electricity with each other. At the same time, the production and distribution of electricity were vertically separated, i.e., they were not allowed in the same legal entity, and the distribution sector remained regulated since the networks were considered natural monopolies. Thus, there is no direct way for the DSOs to influence the amount of electricity that is generated. Each DSO in Sweden has been given monopoly rights in the concession area where they operate. The Swedish Energy Markets Inspectorate regulates the DSOs, and the regulatory framework is based on a revenue cap, outage compensation, and cost-reduction requirements based on Data Envelopment Analysis benchmarks. Further details are included in the Swedish Electricity Act 1997:857 and NordREG (2011).

There were 151 DSOs in Sweden in 2017.[2] This number has declined over several decades, and from 1998 to 2017, the reduction rate was approximately one DSO per year.[3] The DSOs active in 2017 differed markedly in terms of size. The smallest one-third of the firms each had less than 50,000 customers, and the three largest (Vattenfall, E.ON, and Ellevio) had

[2] Our data includes 2018 but it is incomplete since some DSOs have decided to not use calendar year as the basis of their bookkeeping practice. Thus, 2017 is the most recent, complete year, we have access to.
[3] Going further back in time, the Swedish electricity retail distribution sector consisted of approximately 900 firms in 1970, most of which were very small and local (Kumbhakar and Hjalmarsson, 1998).

900,000 – 1,000,000 customers each. Each of the three largest firms were about three times as large as the fourth largest (Göteborg Energi), and they are the only DSOs with networks in several locations of the country. In 2017, 92% of the DSOs had only 34% of the total number of customers. The size distribution of the DSOs is displayed in Table 1.

[Insert Table 1 here]

Another way to describe the size differences is that the largest DSO has as many customers as the sum of the 117 smallest. It should be noted that network regulation is national, and all DSOs are subject to the same regulation (albeit facing individual levels of the revenue cap). Thus, there are no legal reasons some DSOs are small and some are large. To learn more about what is driving the organizational changes in the industry, we will take a closer look at the tails of the size distribution and how they have changed over the last 15–20 years.

To understand the development among the smallest DSOs, we first identify those that were the 25 smallest in 2005 and follow them until 2017 (see Table 2 for details). Six of those merged with other DSOs – some of them with the largest (Vattenfall and Fortum/Ellevio) and the others with much smaller ones (Sandviken Energi, Linde Energi, Gävle Energi, and Brittedals Elnät). The remaining 19 DSOs exist in the same organizational form as they did 12 years earlier. As a side note, it is interesting to note that consolidations only occur between DSOs that are in close proximity to each other. A majority of the acquisitions involved two DSOs that shared a border, while two of the six acquisitions involved DSOs that did not share borders. However, the distances between the borders in those two cases were only a few kilometers.

[Insert Table 2 here]

Could it be that the smallest DSOs have been able to grow without engaging in mergers and acquisitions? To answer this question, we sort out the 25 smallest DSOs each year and use those to calculate the average number of customers those 25 have had each year. Figure 1 shows this information and reveals that an average "small" DSO has increased by about 50% in size from 2001 to 2017, but in absolute term the increase is only 600 customers, which must be considered a modest increase, at best. In fact, much of the increase occurred in 2017 and if that year is excluded, the annual increase will only be 25 customers per year. Since we know that six of those that were among the 25 smallest in 2005 have merged with larger DSOs and that almost 50 DSO have less than 5,000 customers, it is no surprise that the increase is small.

[Insert Figure 1 here]

As the three largest DSOs have most customers than all the other DSOs combined, it is relevant to also look at their development. Figure 2 shows that the three largest actually followed different trajectories 1998–2017: E.ON increased its deliveries until the mid-2000s, and has kept its total number of customers at around 1 million since then. Ellevio reduced its customers slightly until 2009 but has displayed an increasing trend since then and was up by 8 percent in 2017. Vattenfall slowly reduced its customer base during the first half of the sample period but increased it by the same amount in the second half, implying they had almost the same number of customers in 2017 as they did in 1998.

[Insert Figure 2 here]

To summarize, the market structure for the smallest and largest DSOs has not changed much over the last 15-20 years. To understand how this empirical observation relates to the existence of scale benefits, we now turn to the econometric analysis, but first the data characteristics are explained.

3. Data

This section describes the data used in the econometric analysis to determine the scale properties. The Swedish Energy Markets Inspectorate collects financial and technical information from each concession-holder annually. A concession holder is synonymous with a DSO, except for the largest DSOs, which operate several concessions. We compile a dataset based on information reported to the regulator from 1998 to 2018 and focus on variables that are essential to understand electricity network scale properties. These variables are total cost, number of customers, electricity losses, and the prices of capital and electricity, which are two essential inputs.

As a next step, outliers are excluded. The following criteria are used to decide whether an observation is to be excluded:[4] (i) a variable value changes by more than 50% from one year to the next, (ii) a value takes a negative or zero value, and (iii) the number of customers declines by more than 5% from one year to the next.[5] Also, DSOs are excluded if they do not have values for all variables for at least four years. This gives a complete estimable sample consisting of 1,988 observations. The characteristics of these observations are displayed in Table 3 for each of the variables used in the econometric analysis.

[Insert Table 3 here]

A first thing to note in Table 3 is the substantial heterogeneity across distribution firms in terms of both total costs and outputs. For example, total costs vary from approximately 373,000 SEK to more than 4 billion SEK. The DSOs with the lowest total costs are typically small cooperatives. As mentioned, the DSOs with the highest total costs are Vattenfall, owned by the Swedish state, and Ellevio (previously Fortum) and E.ON, both of which are owned by foreign, private investors. The heterogeneity in number of customers and other firm characteristics is also large.

[4] Note that these conditions only exclude single observations and not all observations for that firm or concession area.

[5] I general, network length never decreases from one year to the next. Number of customers can, and do, decrease from one year to the next, but the rate of decline is small in those situations.

Next, we calculate average costs for different firm sizes, where size is represented by number of customers. These cost values are presented in Table 4 across percentiles of number of customers. If there are unexploited economies of scale, this should translate into differences in average costs across firm sizes, where larger firms have lower average costs. As displayed in Table 4, the average cost is clearly higher for smaller firms, and relatively large firms (around the 90th percentile) have the lowest cost. In particular, the lowest average cost in the sample is less than half of the highest average cost. Interestingly, the average cost for the largest firms (99th percentile) are slightly higher than for the 90th percentile. Although these patterns can change when the fully specified models are estimated, it nevertheless suggests that the largest DSOs may not have the lowest cost, i.e., that they are "too large." The performance of the 99th and 100th percentiles is important since these DSOs account for about half of the total number of customers, and even more of the aggregated costs (see Tables 1 and 4).

[Insert Table 4 here]

If all firms had the same average cost as the 90th percentile, i.e. an average cost of 0.14 SEK per kWh, the distribution cost for the average customer would be approximately 18 percent lower than what it is under the current structure (based on numbers from 2018). In a similar vein, if all firms were of the same size as the 90th percentile (approximately 41,000 customers), there would only be 110 DSOs in the country.[6] Thus, if all scale advantaged were exploited, the implications would be substantial.

[6] The cost savings are computed in the following way. First, we compute the total cost under the current structure by summing the total cost over all firms for each year. Next, we compute the aggregate cost under the assumption that each firm has an average cost of 0.14 SEK per kWh. Finally, we compute the percentage

4. Analysis of scale properties

While the descriptive statistics in Table 4 suggest that there are unexploited economies of scale, and possibly also diseconomies of scale for the largest firms, it is useful to proceed with a more rigorous econometric analysis since the descriptive analysis only gives an indication of the relationship between cost and size and ignores other potentially relevant explanatory factors. Thus, in this section we estimate cost functions, which allow us to compute cost elasticities at different percentiles. Intuitively, we expect high percentiles to have a 'number of customers' elasticity of cost, relatively closer to unity.

We estimate average cost (AC) functions that are assumed to be additively separable in outputs and input prices. AC is calculated as total cost divided by delivered electricity. The process of distributing electricity is assumed to consist of one output, i.e., number of customers (N), and two input prices, i.e., the price of capital (p^{cap}) and the price of electricity (p^{el}). While our choice of output variable, as well as input prices, is similar to those used in several previous studies (see, e.g., Triebs et. al., 2016), it should be noted that the choices of output and input variables differ across studies, and in many cases depend on the availability of data. For example, Mydland et al. (2020) use kilometers of high-voltage network and number of customers as outputs, and they do not include input prices due to limited cross-sectional variance in these prices. In our data, input prices vary across both time and firms. Kumbhakar et al. (2015) define a model where there are three outputs: amount of delivered electricity, number of customers, and the length of the network. However, and as discussed by Triebs et al. (2016), when these outputs are included in a

difference between the current and the alternative scenario. The cost savings are larger at the end of the sample period than at the beginning.

model, they tend to create multicollinearity,[7] and this is one of the reasons for using a more parsimonious specification.

Furthermore, we add the following control variables: network losses (L), number of concession areas, DSO fixed effects and year fixed effects. The amount of network losses can be viewed as a hybrid measure that is determined by load, network length, and share of low voltage deliveries. Thus, L captures network congestion, network size and type of customers. More specifically, a higher pressure on the system, i.e., a high load factor, is likely to increase losses, which is expected to increase costs. Losses also increase if electricity is distributed over relatively long distances, and a higher share of high voltage deliveries is associated with less losses. Our results are not affected in any qualitative way if network losses are excluded.

To test the robustness of specifications that only use N as output, we also estimate a specification that aims to capture variation in both number of customers (N) and amount of delivered electricity, Q, by including N and a factor that captures the per-capital electricity demand. In cold climates, such as in Sweden, the strongest determinant of per-capita delivered electricity is the demand for heating. We have access to data from weather stations that record daily temperatures, and after having identified the closest weather stations and calculated the heating degree days (HDD) for each DSO and year, we include that variable together with N.

[7] Using raw data from the Swedish Energy Markets Inspectorate, the correlation between delivered electricity and number of customers is 0.997 and the correlation between delivered electricity and cable length is 0.966.

The price of capital, p^{cap}, is defined as the sum of depreciations and interests divided by the value of total operational assets. Operational assets are used as a proxy for the stock of capital since inventory data are not available.[8] While similar definitions have been used previously in the literature on electricity distribution, see, e.g., Nemoto and Goto (2006), we note that owners' rates of return are not included since they are not reported by the DSOs. However, the Swedish Energy Markets Inspectorate has concluded that variations in the weighted average cost of capital are primarily due to variations in the interest rate. The price of electricity, p^{el}, is included because DSOs purchase electricity to cover network losses and pay for transit on the high voltage network. This price is calculated as the total cost of transit and losses divided by the sum of losses and high voltage deliveries.

Cost functions that represent physical networks have been specified using various approaches, such as the Cobb-Douglas form (e.g., Söderberg, 2008), the Translog form (e.g., Söderberg, 2011 and Triebs et al., 2016), the quadratic form (e.g., Jamasb and Söderberg, 2010 and Mydland et al., 2020), and forms derived based on theoretical, energy-specific, principles (e.g., Boscan and Söderberg, 2021). At a minimum, the chosen specification should be able to identify both linear and nonlinear output effects and both economies and diseconomies of scale.

There is no consensus regarding what variables to include and what specification to choose.[9] In this study, we use a quadratic form of N and estimate four different models where different squared and interaction terms are included.[10] Eq. (1) includes squared terms of L, eq. (2)

[8] A measure of capacity can be used as an alternative to assets, but as pointed out by Aubert and Reynaud (2005), it would not reflect the total capacity or depreciation, irrespective of how carefully it is chosen.
[9] See, e.g., the literature review by Söderberg (2008, pp. 65–66).
[10] The rationale for the quadratic form, rather than the more frequently adopted translog, is threefold (Färe et al., 2009; Shaffer, 1998): (i) the quadratic form handles many fixed terms more readily, (ii) it does not rest on the profit-maximizing assumption (which is likely to be overly restrictive for publicly owned utilities) like the

includes square terms and an interaction between N and L, and eq. (3) includes no squared or interactions terms for the control variables. Eq. (4) is similar to eq. (1) but includes heating degree days (HDD) as an extra covariate. All continuous variables are in logs. The four specifications can be formulated as:

$$AC_{it} = \alpha_0 + \alpha_1 N_{it} + \alpha_2 N_{it}^2 + \alpha_3 L_{it} + \alpha_4 L_{it}^2 + \alpha_5 p_{it}^{cap} + \alpha_6 p_{it}^{el} + \lambda_i + \theta_t + \varepsilon_{it}, \tag{1}$$

$$AC_{it} = \beta_0 + \beta_1 N_{it} + \beta_2 N_{it}^2 + \beta_3 L_{it} + \beta_4 L_{it}^2 + \beta_5 N_{it}\, L_{it} + \beta_6 p_{it}^{cap} + \beta_7 p_{it}^{el} + \lambda_i + \theta_t + \varepsilon_{it}, \tag{2}$$

$$AC_{it} = \gamma_0 + \gamma_1 N_{it} + \gamma_2 N_{it}^2 + \gamma_3 L_{it} + \gamma_4 p_{it}^{cap} + \gamma_5 p_{it}^{el} + \lambda_i + \theta_t + \varepsilon_{it}, \tag{3}$$

$$AC_{it} = \theta_0 + \theta_1 N_{it} + \theta_2 N_{it}^2 + \theta_3 L_{it} + \theta_4 L_{it}^2 + \theta_5 HDD_{it} + \theta_6 p_{it}^{cap} + \theta_7 p_{it}^{el} + \lambda_i + \theta_t + \varepsilon_{it}, \tag{4}$$

where i is DSO, t is year, λ_i and θ_t are DSO and year fixed effects, respectively, ε_{it} is the random noise, which is assumed to be i.i.d., and $\boldsymbol{\alpha}, \boldsymbol{\beta}, \boldsymbol{\gamma}$, and $\boldsymbol{\theta}$ are vectors of parameters to be estimated.

Equations (1) – (4) are estimated with the within-estimator. The full estimation output is displayed in Appendix A and here we focus on the scale elasticities, i.e., $\frac{\partial AC}{\partial N}\frac{N}{AC}$. As displayed in Table 5, the elasticity is calculated at different percentiles for each equation, similar to Mydland et al. (2020). As shown, all elasticities, except those at the 99th percentile, are negative, suggesting that the average cost function is falling for almost all of the DSOs. Broadly speaking, the elasticity enjoyed by the smallest DSOs is around -1.4 and the largest DSOs around 0.5. The results at the sample mean are similar to those in previous studies

translog form, and (iii) the quadratic form has been found to generally outperform most other forms, including the translog.

based on data from the Nordic countries (e.g., Kumbhakar and Hjalmarsson, 1998, Kumbhakar et al., 2015, Mydland et. al., 2018, and Mydland et. al., 2020).

The fact that the elasticities are positive for the largest DSOs indicates that they have exceeded the cost minimizing point and that they operate at upward sloping section of the AC-function. Thus, the largest DSOs should evaluate future acquisitions carefully to avoid the cost to increase their AC further. There is also a more general danger in pushing N beyond its current maximum point since it is uncertain what the functional properties look like when values are extrapolated. Previous studies have also found that the largest DSOs are "too large". For example, Kumbhakar et al. (2015) found that the 2–6% largest Norwegian DSOs have a size that is a least 5% above the optimal level. For the small- and medium-sized DSOs, it is clear that they can lower their average cost if they increase N. This poses the question of why these DSOs have not been more actively involved in mergers and acquisitions.

[Insert Table 5 here]

Table 6 gives detailed insights about how the average costs is affected by increases in N. The AC baseline (column 2) reports current AC levels using the actual values of control variables and input prices, which is the reason AC is higher for the 95th percentile than for the 90th percentile. Since the smallest DSOs (1st percentile) have an average cost that is about twice as high as the DSOs in the other tail of the distribution (e.g., 90th and 95th percentiles), the smallest DSOs can make substantially larger savings by increasing their customer bases. For example, a ten percent increase in N results in an absolute decrease of the AC that is 10-20 times as large for the smallest DSOs as some of the largest DSOs. If the increase in N is fixed at a certain number of customers, then the smallest DSOs have incentives to merge that are more than 100 times greater than the largest firms. In the next section, we report the results from a qualitative survey on consolidations and reasons DSOs have or have not engaged in consolidations.[11]

[Insert Table 6 here]

5. Questionnaire to DSOs

Annual regulatory statistics do not contain information about ownership, which creates a delay in when information about mergers and acquisitions becomes available. Thus, the first question we asked DSOs is what ownership transactions they were involved in from January 1, 2018–December 31, 2019. There are several potential reasons DSOs had or had not been involved in consolidation processes with other DSOs. Inactivity could, for example, be due to scale economies having been exhausted, the regulatory framework not creating incentives for mergers, current owners not wanting to lose their influence over important investment or pricing decisions, the processes taking time, making it look like the level of activity was low, or the current owners having objectives that are different from those of potential buyers. One way to learn about the decisions made by the DSOs is to ask them directly.

The questionnaire was sent out to all firms that report financial and technical statistics to the Swedish Energy Markets Inspectorate on an annual basis. The response rate reached 63.2%

[11] Given the results in this section, it is unlikely to see divestitures. However, we do not restrict responses from DSOs that describe divestitures, nor do we explain why they engaged or did not engage in divestitures.

after a reminder (responses received from 96 DSOs). Two DSOs replied that they did not want to participate in the survey. Table 7 displays the transactions that were revealed from the questionnaire. The table shows the predicted average costs[12] for both buyers and acquired organizations prior to, as well as after, the transactions. In addition to the transactions reported in Table 7, one respondent revealed that the DSO had initiated an acquisition process, but that it withdrew from the process after realizing it would not be as profitable as initially expected. Another DSO replied that it had submitted a number of bids to purchase other DSOs, but that they had not been accepted by the target owners.

[Insert Table 7 here]

Five of the DSOs that responded to the questionnaire reported that they had been involved in consolidations. Thus, the conclusion is that merger and acquisition intensity remain low in the industry, despite the noticeable benefits it can bring. Ellevio, one of the three largest, has continued to purchase smaller firms, but as shown above, there is no guarantee that with as many customers as Ellevio has, there is no guarantee that consolidations will reduce the average cost. However, the DSOs that were acquired are all relatively small and they have enjoyed noticeable cost reductions. The firms gave only one reason for not being more active, either as an acquirer or a target, namely that the financial gains were not large enough. Of course, this does not mean that mergers and acquisitions do not result in cost savings, but that the DSOs involved do not get to keep the rewards that follow the structural change. This may seem a bit odd, since it has been claimed that the Swedish electricity distribution regulation

[12] Similar to table 4, we first compute the predicted total cost, and then divide by demand to get average costs.

is weak relative to other westerna European countries and that it favours the DSO at the expense of customers (Söderberg and Yang, 2021). No firm claimed to avoid consolidation because it did not want to lose influence over important business decisions, or in order to self-regulate according to its own values and preferences.

While it is uncertain whether it is economically desirable for the largest DSOs to grow their networks, it seems clear that the small- and medium-sized DSOs can reduce their average costs. If the DSOs conclude that the net financial gain of consolidations is limited, then the regulatory structure can be adjusted, and there are several ways to do that. First, the future revenue cap for a consolidated DSO can be calculated as the sum of the caps based on the two pre-consolidated DSOs, i.e., excluding any economies of scale from the consolidation. Insofar as the two DSOs can exploit economies of scale when they merge, they get to keep that financial benefit during the next regulatory period, or for as long as the regulator decides. The larger the scale benefits, the larger the incentives to consolidate, which implies that smaller DSOs will have stronger incentives than medium and large ones to consolidate. Second, if the cap-to-cost ratio does not increase (sufficiently) for more customers, relatively smaller DSOs have insufficient incentives to engage in time-consuming and complex consolidation processes. For the Swedish DSOs in 2018, this ratio is practically constant as a function of number of customers (see Figure 3), which gives the DSOs no direct incentives to consolidate. The regulator could give DSOs above a certain size a cap premium to stimulate smaller DSOs to merge.

[Insert Figure 3 here]

Conclusions

If the number of customers increase by 10%, the smallest Swedish electricity DSOs will lower their average cost by 10-15%. While on average about one small DSO merges with a larger counterpart every two years, one may ask why not more of the small DSOs have taken advantage of the substantial cost advantages that consolidations can bring. To understand this inactivity, a questionnaire was sent out to all DSOs at the end of 2020, and it revealed that the DSOs do not think mergers and acquisitions are financially worthwhile. Simulations based on our econometric estimations confirm this. This leads to the conclusion that the regulatory model needs to change for society to benefit from the unexploited scale benefits. A policy that gives financial rewards to medium and large networks would create stronger incentives for the small DSOs to consolidate. One approach could be to calculate the revenue cap in the post-consolidation regulatory period based on the pre-consolidation cost level.

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TABLES

Table 1. Size distribution of Swedish electricity DSOs.

Number of customers	Number of firms
<5,000	47
5,000 - 10,000	25
10,000 - 15,000	27
15,000 - 20,000	12
20,000 - 30,000	18
30,000 - 50,000	9
50,000 - 100,000	7
>100,000	6

Table 2. Development of the DSOs that were the 25 smallest in 2005.

The 25 smallest DSOs in 1998/1999	One of the 25 smallest DSOs in 2005?	One of the 25 smallest DSOs in 2010?	One of the 25 smallest DSOs in 2017?	Comment
LJW Nät HB	Yes	Yes	No	Owned by Vattenfall and incorporated in one of Vattenfall's concession areas in 2014. Vattenfall was a neighboring DSO that shared a border with LJW Nät HB.
Sturefors Eldistribution AB	Yes	Yes	Yes	
Hamra Besparingsskog	Yes	Yes	Yes	
Almnäs Bruk AB	Yes	Yes	Yes	
Österfärnebo El eko. för.	Yes	Yes	No	Owned by Sandviken Energi and incorporated in Sandviken Energi's concession area in 2017. Sandviken Energi was a neighboring DSO that shared a border with Österfärnebo El eko. för.
Vinninga Elek. för.	Yes	Yes	Yes	
Envikens Elnät AB	Yes	Yes	Yes	
Årsunda Kraft & Belysningsför. upa	Yes	Yes	Yes	
Olseröds Elek. Distr.för. upa	Yes	Yes	Yes	
Närkes Kils Elektriska eko. för.	Yes	Yes	No	Acquired by Linde Energi 1 Jan 2015. Närkes Kils Elektriska eko för was a close neighbor but did not share a border with Linde Energi .
Blåsjön Nät AB	Yes	Yes	Yes	
Hedesunda Elektriska AB	Yes	Yes	No	Owned by Gävle Energi AB, and incorporated in Gävle Energi AB's concession area, from 2011. Hedesunda Elektriska AB was a neighboring DSO that shared a border with Gävle Energi AB.
Skyllbergs Bruks AB	Yes	Yes	Yes	
Töre Energi eko. för.	Yes	Yes	Yes	
Hjärtums Elförening eko. för.	Yes	Yes	Yes	
Hallstaviks Elverk eko. för	Yes	Yes	Yes	
Mellersta Skånes Kraft	Yes	Yes	Yes	
Näckåns Elnät AB	Yes	Yes	Yes	
Nor-Segerstad	Yes	No	No	Incorporated in Fortum's concession area 2006. Nor-Segerstad was a neighboring DSO that shared a border with Fortum.
Sjogerstads Elek. Distr.för. eko. för.	Yes	Yes	Yes	
Nossebroortens Energi eko. för.	Yes	No (26th smallest)	Yes	
Bengtsfors Energi Nät AB	Yes	Yes	Yes	
Åkab Nät & Skog AB	Yes	Yes	Yes	Changed names to Åsele Elnät AB (same concession area as earlier)
Kviinge El eko. för.	Yes	Yes	No	Acquired by Brittedals Elnät eko. för. 1 Jan 2013. Kviinge El eko för was a close neighbor but did not share a border with Brittedals Elnät eko. för.
Vallebygdens Energi eko. för	Yes	Yes	Yes	

Larvs Elektriska Distributionsförening was one of the smallest from 2003. Data is missing before 2003. Incorporated in Kvänumbygdens Energi eko. För.'s concession area from 2013. The geographical borders of the network concessions can be viewed at www.natomraden.se.

Table 3. Descriptive statistics.

Variable [unit]	Obs	Mean	Std. Dev.	Min	Max
Total costs [thousand SEK]	1988	120,100	461,100	372.8	4,346,000
Delivered electricity [MWh]	1988	635,000	2,224,000	1,298	$1.88{\times}10^{7}$
No. of customers [#]	1988	35,760	131,600	143	1,031,000
Loss [MWh]	1988	25,790	94,590	104	1,023,000
Price of capital [SEK per SEK]	1988	0.5520	0.7010	0.0320	8.8510
Price of electricity [SEK per MWh]	1988	14.551	18.289	1.964	667.75

Table 4. Average cost [SEK per kWh] across percentiles

Percentile (Number of customers) [a]	**Avg cost**
1st (200)	0.287
5th (1,000)	0.230
10th (1,800)	0.283
25th (4,100)	0.222
50th (10,200)	0.185
75th (19,500)	0.167
90th (40,800)	0.133
95th (61,400)	0.158
99th (874,300)	0.193

Note. [a] Rounded to the nearest hundred.

Table 5. Elasticities at different percentiles for eqs. (1) – (4).

Percentile (Number of customers) [a]	Eq. (1)	Eq. (2)	Eq. (3)	Eq. (4)
1st (200)	-1.387	-1.369	-1.406	-1.387
5th (1,000)	-0.997	-0.946	-1.022	-0.997
10th (1,800)	-0.846	-0.792	-0.873	-0.846
25th (4,100)	-0.674	-0.636	-0.704	-0.674
50th (10,200)	-0.475	-0.444	-0.508	-0.475
75th (19,500)	-0.323	-0.297	-0.358	-0.323
90th (40,800)	-0.152	-0.132	-0.190	-0.152
95th (61,400)	-0.072	-0.078	-0.111	-0.072
99th (874,300)	0.512	0.507	0.463	0.512

Note. [a] Rounded to the nearest hundred

Table 6. Average cost (AC) baseline values and how AC is affected if N increases.

Percentile (Number of customers) [a]	AC baseline	AC when N increases by 10%	AC when N increases by 20%
1st (200)	0.2904	0.2506	0.2108
5th (1,000)	0.2566	0.2323	0.2080
10th (1,800)	0.2983	0.2746	0.2510
25th (4,100)	0.2357	0.2207	0.2057
50th (10,200)	0.1924	0.1838	0.1753
75th (19,500)	0.1784	0.1731	0.1678
90th (40,800)	0.1401	0.1382	0.1364
95th (61,400)	0.1672	0.1658	0.1646
99th (874,300)	0.2095	0.2201	0.2307

Note. [a] Rounded to the nearest hundred.

Table 7. Mergers and acquisitions in 2018 and 2019 revealed by DSOs responses.

	Before the acquisition		**After the acquisition**
	Buyer	***Target firm***	***New firm***
Transaction 1:			
DSO	Lidköping kommun	Vinninga elektriska förening	Lidköping kommun
Number of cust.*	21,827	824	22,651
Average cost**	0.226	0.873	0.223
Cost saving			1.45%
Transaction 2:			
DSO	Kraftringen Energi AB	Skånska Energi elnät AB	Kraftringen Energi AB
Number of cust.*	100,647	18,725	119,372
Average cost**	0.087	0.158	0.083
Cost saving			4.38%
Transaction 3:			
DSO	Ellevio	Hamra Besparingsskog	Ellevio
Number of cust.*	959,944	514	960,458
Average cost**	0.055	1.301	0.0595
Cost saving			0.004%
Transaction 4:			
DSO	Falu Elnät AB	Envikens Elnät AB	Falu Elnät AB
Number of cust.*	32,105	1,181	33,286
Average cost**	0.129	0.691	0.127
Cost saving			1.17%
Transaction 5:			
DSO	Ellevio	Vallentuna Elnät AB	Ellevio
Number of cust.*	959,944	14,732	974,676
Average cost**	0.055	0.187	0.054
Cost saving			0.24%

* Number of customers before the acquisition is the value the year before the transaction took place. Number of customers after the transaction is the sum of the two numbers before the transaction.
** The average cost is calculated based on eq. (1) with the parameters reported in Table A1.

FIGURES

Figure 1. Number of customers, the average of the 25 smallest DSOs in each year.

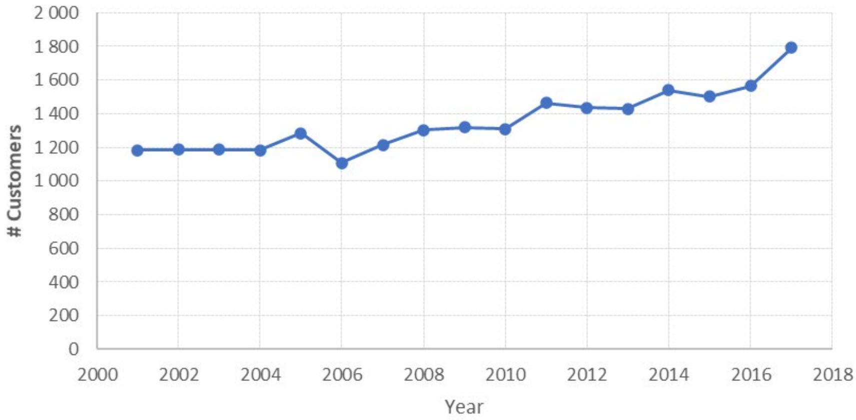


Figure 2. Number of customers, the three largest DSOs.

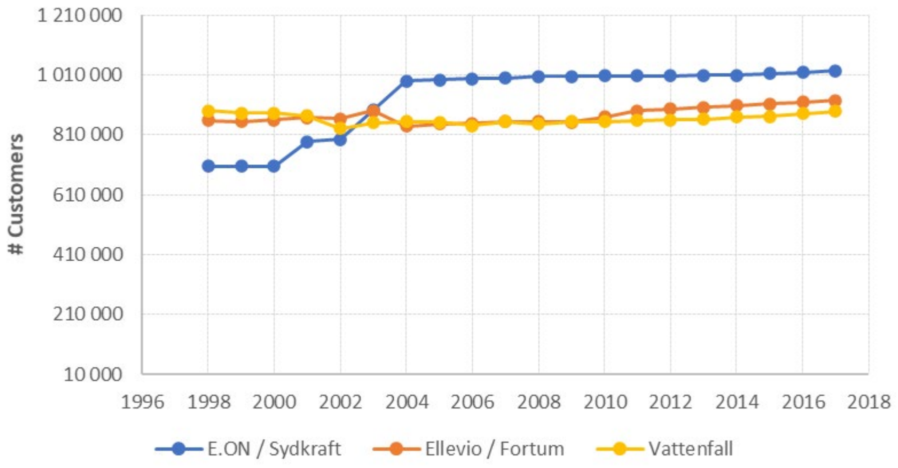
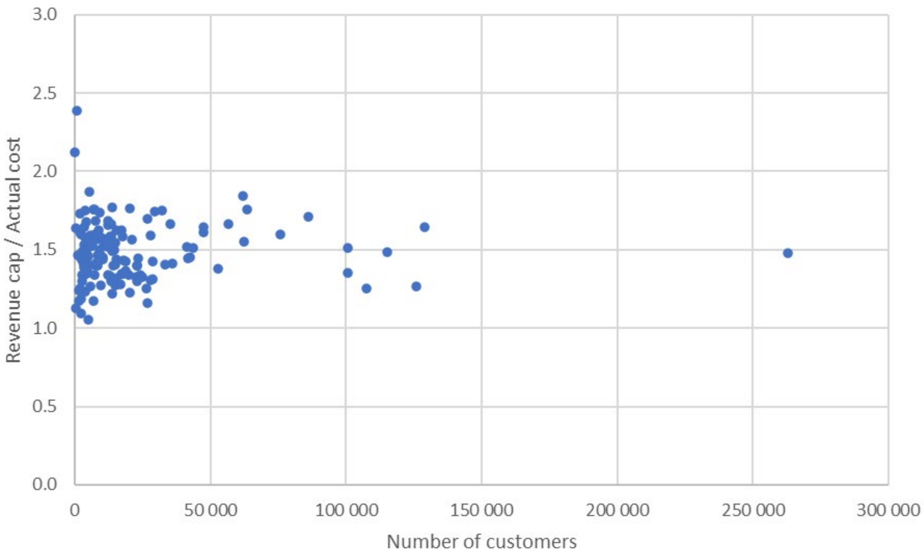


Figure 3. The cap-to-cost ratio as a function of number of customers. The horizontal relationship suggests that small firms have no incentive to merge with other firms. The three largest firms (E.ON, Vattenfall, and Ellevio) have been excluded in this graph to make the relationship below 300,000 customers more visible. However, the three largest are positioned almost exactly on the horizontal line with ratios close to 1.5.



Appendix A

Table A1. Estimation output from eq. (1) – (3).

Variable	**Eq. (1) Coeff (S.E.)**	**Eq. (2) Coeff (S.E.)**	**Eq. (3) Coeff (S.E.)**	**Eq. (4) Coeff. (S.E.)**
Number of customers	-2.517*** (0.461)	-2.432*** (0.460)	-2.519*** (0.462)	-2.517*** (0.461)
Number of customers squared	0.110*** (0.022)	0.155*** (0.025)	0.109*** (0.022)	0.110*** (0.022)
Loss	0.309*** (0.070)	0.431*** (0.077)	0.087*** (0.011)	0.309*** (0.070)
Loss squared	-0.013*** (0.004)	0.031** (0.013)		-0.013*** (0.004)
Number of customers × Loss		-0.098*** (0.027)		
Heating degree days				0.000 (0.000)
Price of electricity	0.168*** (0.010)	0.171*** (0.010)	0.163*** (0.010)	0.169*** (0.010)
Price of capital	-0.029*** (0.008)	-0.029*** (0.008)	-0.029*** (0.008)	-0.029*** (0.008)
Number of concession areas	Yes	Yes	Yes	Yes
DSO FE	Yes	Yes	Yes	Yes
Year FE	Yes	Yes	Yes	Yes
Constant	10.645*** (2.407)	9.570*** (2.416)	11.681*** (2.391)	10.640*** (2.407)
R2 (within)	0.4973	0.4353	0.4232	0.4973
N	1987	1987	1987	1987

Note: All variables are logged.