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Vertical disintegration in the European electricity sector: Empirical evidence on lost synergies

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ABSTRACT

The EU has been promoting unbundling of the transmission grid from other stages of the electricity supply chain with the aim of fostering competition in the upstream stage of electricity generation. At present, ownership unbundling is the predominant form of unbundling in Europe. From a policy perspective, a successful unbundling regime would require that the benefits of increased competition in power generation would at least offset the associated efficiency losses from vertical divestiture. Since evidence on this topic is scarce, this study helps fill this void by empirically estimating the magnitude of economies of vertical integration (EVI) between electricity generation and transmission based on a quadratic cost function. For this purpose we employ unique firm-level panel data of European electricity utilities. Our results confirm the presence of substantial EVI of 14% for the median sized integrated utility. Moreover, EVI tend to increase with firm size.

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1. Introduction

Before the introduction of liberalization and regulatory reforms in order to promote competition in the European electricity sector, electricity utilities were generally regarded as vertically integrated natural monopolies. In the classical fashion, vertical integration of upstream and downstream operations was the predominant organizational form of an electricity utility to benefit from scope economies of vertical integration (EVI). A fully vertically integrated electricity company would encompass all stages from electricity generation to high-voltage transmission of electricity and local distribution, in conjunction with system operations, retailing to final consumers, and wholesale power procurement (e.g. Hunt, 2002). It seems natural that vertical integration exhibits cost savings through coordination advantages, sharing of information, use of common inputs, sharing of staff, efficient planning of investments, protection against uncertainty and financial risk, among other factors, which cannot be easily realized by unbundled firms (Jara-Díaz et al., 2004; Meyer, 2012a, 2012b).

Electricity is a particularly special good which includes some important characteristics: (i) on a large scale, electricity cannot be easily stored, which requires supply to meet demand at all times. Therefore, suppliers need to have sufficient excess capacities to meet peak demand. (ii) Electricity follows physical laws (Ohm's and Kirchoff's laws) and flows its way of least resistance. (iii) Usually, generated electricity has to be transported to customers via long-distance high-voltage transmission lines and locally via lower-voltage distribution lines (Arocena et al., 2012; Ramos-Real, 2005). Under these conditions, the supply of electricity is highly interlinked along the various supply stages and, accordingly, subject to coordination requirements (Gugler et al., 2013). Hence, vertical integration seems to be a more efficient organizational form in electricity compared to leaving the coordination of vertical supply to the market (Arocena et al., 2012).

In recent decades, the unbundling principle (i.e. vertical separation) has been put into practice in many economies around the globe. This regulatory measure aims at isolating some segments of the electricity supply chain which do not exhibit the usual properties of a natural monopoly (e.g. generation, retail) for the sake of eliminating anti-competitive forces and lowering the electricity price for end-consumers through increased competition (Fraquelli et al., 2005). The remaining segments – the transmission grid and the distribution lines – feature typical network characteristics associated with a natural monopoly and, thus, need to be regulated.[1]

However, a controversial debate has arisen whether the benefits of increased competition may be offset by potentially increased costs of utilities from unbundling.[2] The policy discussion has brought little attention to the fact that the regulatory measure of vertical disintegration comes at a cost, namely the destruction of vertical economies. According to

[1] For example, by introducing price regulation (grid tariffs) and third party access.

[2] Sappington (2006) discusses the benefits of vertical divestiture to maximize consumer welfare despite the presence of substantial vertical economies. Gugler et al. (2013) show that there is a trade-off between static and dynamic efficiency in this context.

Meyer (2012a) the greatest vertical synergies occur between *generation* and *transmission*, for which the largest cost savings are to be expected. This is, because coordination needs are particularly pronounced between upstream power plants and their direct connection to the downstream transmission network (opposed to the indirectly linked distribution network). Against this backdrop, it is important to assess if and how large these EVI may be. Lost vertical economies might present a significant barrier for an unbundling regime to be successful.

Indeed, the European Union has already put vertical disintegration of the high-voltage *transmission* grid into practice (starting with the EU directive 1996/92/EC; Schmitt and Kucsera, 2014).[3] Therefore, vertical structures of electricity utilities have been broken up, and simultaneously, third party access to the transmission grid has been granted for entrants. The most recent EU directive 2009/72/EC requires its member states to choose from three different forms of vertical unbundling of the transmission grid: (i) full ownership unbundling (the predominant form in Europe), (ii) the implementation of an independent system operator (ISO), or (iii) the implementation of an independent transmission operator (ITO).[4] Among them, ownership unbundling represents the most restrictive type, where vertically integrated electricity utilities have to fully separate from their transmission grid.

The political discussion about vertical synergies and the unbundling of electricity utilities has, of course, not been limited on Europe only; it also has been a controversial topic in the United States (Joskow, 2005a) and many other parts of the world (Pollitt, 2008). Common to the European as well as to the US electricity sector has been the fact that prior to liberalization, both sectors have been characterized by a high degree of vertical integration (Meyer, 2012b). However, the structures of the electricity industries and their regulatory frameworks differed and still differ in many respects (Joskow, 2005a). The US electricity supply industry for instance has been highly fragmented, as it developed from small, local systems that were weakly integrated. Consequently, the level of integration among transmission networks has been traditionally rather low. At the same time, there has not been an overall and coherent US-wide regulatory regime in place, since most utilities have been regulated by the individual states' Public Utility Commissions. The Federal Energy Regulation Commission (FERC) has only been responsible for utilities that operate across states borders. In contrast, the integration of transmission networks as well as the harmonization of regulatory regimes in the European Union is more advanced, which is primarily driven by the European Commissions' policy.

While the empirical literature in general finds considerable cost savings from vertical economies for US electricity utilities, limited empirical literature on single-country studies points toward modest cost savings in Europe. In brief, empirical evidence questions the effectiveness of the divestiture of integrated utilities in the electricity industry, whereby evidence from Europe is scarce and not as distinctive as from the US. Noticeably, not

[3] In contrast, the level of unbundling of *distribution* lines lags far behind.
[4] Balmert and Brunekreeft (2010) provide a description of the various forms of transmission unbundling.

only the regulatory framework but also the structure of the electricity industry differ between the US and Europe in many respects (as indicated above), which makes a direct comparison difficult (Meyer, 2012a). Moreover, the predominant share of the literature concentrates on the estimation of scope economies between the stages of generation and *distribution*, for which data seem to be more easily available. In contrast, there is hardly any evidence on cost savings from integration between generation and *transmission*. Since the EU law explicitly requires unbundling of the transmission grid, such information would be of utmost relevance.

A key feature of this study is to concentrate on the efficiency and effectiveness of vertical divestiture of the supply stages of *generation* and *transmission* of European electricity utilities, while most of the literature has focused on *distribution* unbundling. To achieve this goal, we quantify EVI based on the estimation of a multistage quadratic cost function. If vertical economies were found to be large, it would indicate that the regulatory measure of ownership unbundling of the transmission grid may come at substantial costs.

We utilize novel firm-level data on 28 major European electricity utilities from 16 European countries for the annual date for the period 2000–2010. Data are collected from annual reports and combined with data sources from Platts, Orbis, Worldscope, Eurostat and OECD. To the best of our knowledge, the paper is the first to provide empirical cross-country evidence for Europe regarding economies of scope from vertical integration in the electricity sector. The data allow for identifying vertical economies through mixed company structures, since the sample represents all organizational forms of generators, transmitters, and vertically integrated utilities.

We find that vertical integration between generation and transmission is associated with significant cost savings. This is of high policy relevance, since this places a non-negligible hurdle for an unbundling regime to be successful. For the median sized integrated utility having 45.5 TWh electricity generation and 5500 km of lines, EVI are around 14%. Given the skewness of the sample, the much larger mean sized integrated utility (i.e. 117.4 TWh electricity generation and 14,700 km of lines) obtains EVI in the magnitude of 21%. Hence, there is evidence that large operators tend to benefit more from vertical integration. Also, at larger scales, variable cost savings tend to be more pronounced compared to fixed cost savings. Our results shed some light on the consequences of transmission unbundling as a regulatory means. This is of particular interest not only to regulatory authorities and policy-makers who are concerned with the optimal form of regulation, but also to end-consumers who eventually have to finance the electricity system via electricity taxes and (higher) prices. Moreover, these findings are consistent with existing findings regarding the cost increases associated with deregulation (unbundling) in other parts of the world, like the US.

The findings also complement the academic literature as we provide evidence on the mechanisms underlying the EVI. We find that asset specificity and market complexity are potential sources of vertical cost synergies because they increase the coordination requirements between generation and transmission. Specifically, we subject EVI to utilities' innovativeness (patents), increasing penetration from intermittent renewable sources, and market fragmentation. We find that EVI are more important for innovative firms, if there is more penetration from intermittent renewables, and if market fragmentation is larger. In this context, policies to internalize externalities from asset specificity and market complexity are desirable. In particular, such policies may foster market forces, target the hold-up risk of sunk costs, try to integrate intermittent renewable sources of energy, and enhance the performance of institutions in order to meet the inherent coordination needs between generation and transmission.

The paper is organized as follows. Section 2 provides a summary of the relevant literature about scope economies in the electricity sector. Section 3 describes the theory on scope economies and their potential sources. The model specification and estimation strategy are presented in Section 4. Section 5 discusses the underlying data for the econometric analysis. The results are provided in Section 6, where we present regression results and robustness checks. Section 7 digs deeper into the sources of economies of vertical integration and analyzes the dimensions of asset specificity and coordination requirements in greater detail. Section 8 summarizes the findings and derives policy implications.

2. Review of relevant empirical literature on vertical economies in electricity

The main body of the empirical literature on vertical economies in the electricity sector investigates the stages of generation and the network, where the latter is either represented by the distribution network or a combination of the distribution and the transmission network. Some early works have concentrated on the separability and sub-additivity of the vertical supply stages in the electricity sector (e.g. Gilsdorf, 1994; Hayashi et al., 1997; Lee, 1995; Roberts, 1986; Thompson, 1997). The findings generally indicate non-separability of the cost function,[5] which points toward the presence of vertical scope economies. Subsequently, empirical studies have started to directly implement the concept of multi-output theory with the primary appeal to estimate the *magnitude* of vertical synergies in the electricity markets. Both Arocena et al., (2010) and Ramos-Real (2005) provide thorough literature reviews. In the following, we discuss the relevant literature on vertical cost synergies in the US and European electricity sectors. In doing so, we put emphasis on the stages of generation and distribution, as well as generation and transmission.

A great deal of the empirical nexus on scope economies from vertical integration between generation and *distribution* focuses on the US. The paper by Kaserman and Mayo (1991), who apply a quadratic cost function and estimate 12% cost savings at the sample mean for 74 US electricity companies in 1981, was a seminal contribution. Hayashi et al. (1997) focus on 50 US utilities with at least 85% of generation from fossil fuels for the period 1983–1987 and apply a translog cost function. The results show vertical economies of around 17% for the average utility (a sample split into small

[5] Non-separability of the cost function means that downstream activities of transmission and distribution are dependent on upstream generation.

and large utilities shows evidence of vertical economies of 14% and 17%, respectively). Kwoka (2002) examines data on 147 US utilities for the year 1989 and finds substantial vertical economies based on a quadratic cost function. While for very small utilities, stand-alone production is a viable strategy, larger companies profit from cost savings from vertical integration. At the median and mean level, scope economies are calculated at 27% and 42%, respectively. Greer (2008) utilizes a sample of 831 rural US utilities in 1997. Estimates from a modified quadratic cost function reveal cost savings from vertical integration for basically all utilities. Similar to Kwoka's (2002) findings, economies of scope for the average utility are in the order of 40%.

Triebs et al. (2016) apply a flexible approach of the cost function by allowing for differences in technologies across integrated and specialized firms. Their results from an unbalanced panel of US utilities for the period 2000–2003 indicate moderate scope economies of 4.4%, putting previous findings into perspective. Arocena et al. (2012) incorporate data on 116 US investor-owned utilities for the year 2001 and estimate a quadratic cost function. Vertical economies are estimated in the scope of eight percent, while horizontal economies (across different types of generation) make up around 5.5% for the average utility.

In contradiction to the pronounced empirical literature on the US electricity industry, the European literature on multi-output cost-function estimation of vertical scope economies is relatively limited. To the best of our knowledge, there are merely single country studies but no cross-country analyses. The Spanish electricity market has been investigated by Jara-Díaz et al. (2004), who employ an unbalanced panel of 12 Spanish electricity utilities for 1985–1996. The average firm in their sample exhibits vertical economies of 6.5% and horizontal economies of around ten percent. With regard to Italy, Fraquelli et al. (2005) make use of a composite cost function on 25 municipal electric utilities for the period 1994–2000 and estimate vertical cost savings of 3%. The same dataset is used by Piacenza and Vannoni (2004),[6] who compare estimates from different cost function specifications (generalized translog, standard translog, separable quadratic, composite, and general).[7] Their preferred model, the composite form, yields vertical economies in the magnitude of 6% for the median utility. Fetz and Filippini (2010) concentrate on the Swiss electricity sector. The estimation of a quadratic cost function for 74 utilities over 1997–2005 yields substantial vertical economies far beyond 40% on average.[8] This may be explained by the relatively small size of the sample utilities having generally less than 100,000 customers.

As far as we know, Meyer (2012a) is the only empirical study to investigate scope economies between electricity generation and *transmission*. Based on data from the US for the period 2001–2008, his findings indicate modest vertical synergies between the two stages of approximately four percent for the average firm. This is explained by a *coordi-*

[6] In contrast to Fraquelli et al. (2005), Piacenza and Vannoni (2009) employ different output measures, with the purpose of investigating not only vertical but also horizontal economies at the distribution stage.
[7] The composite and general forms are implemented according to Pulley and Braunstein (1992).
[8] The exact magnitude of vertical economies for the mean or median utility is not provided in the paper.

nation effect from transaction cost theory: "firm internal coordination is expected to be more efficient than market coordination as a result of costly, incomplete and/or inflexible contracts of market participants pursuing different or opposing interests" (Meyer, 2012a, p. 105). Yet, Meyer warns against a potential bias of a comparison of his results with findings for Europe because of different market structures and initial unbundling conditions.[9] Besides, his results show the presence of vertical economies between generation and the whole network of transmission plus distribution of 19–26% and vertical economies between distribution (including retail) and generation plus transmission of eight to ten percent.

Against this review of the empirical literature, vertical economies of scope in the electricity industry appear to exist, whereas contrasting findings regarding the *magnitude* of estimated cost savings from vertical integration may stem from different factors. Among them are: (i) the heterogeneity of utilities (e.g. size, corporate form, geographic region, regulatory framework) included in the data; (ii) the specification of the cost function; (iii) different measures of outputs and inputs; and (iv) diverging periods of observation. Some evidence from US electricity markets corroborates the presence of substantial cost savings from vertical integration. Clearly, vertical synergies in the European electricity sectors are under-researched, foremost because only single countries have been investigated. Overall, the effectiveness of vertical ownership unbundling is being questioned despite its potential positive effects (e.g. increased competition, lower end-consumer prices). Since European cross-country scrutiny is missing, the purpose of this paper is to help fill this void in the literature.

3. Multiproduct theory and sources of vertical economies

The concept of economies of scope is rooted in the multiproduct production theory which is based on the idea that there may be potential cost savings from jointly producing two outputs in contrast to producing them separately. Transaction theory provides the explanation that "firm internal coordination is expected to be more efficient than market coordination" (Meyer, 2012a, p. 105). Consequently, the vertically integrated supply of upstream electricity generation and downstream electricity transmission may be more cost-efficient than a separated production process, as suggested by transmission ownership unbundling. Hence, vertical scope economies are in place if the costs of separating the supply stages of generation (Y_G) and transmission (Y_T) exceed their combined production costs:

$$C(Y_G, 0) + C(0, Y_T) - C(Y_G, Y_T) > 0. \tag{1}$$

The magnitude of economies of vertical integration (EVI) can be measured as the cost savings of jointly serving both stages relative to the costs of separated supply

[9] In the US, many states have implemented Regional Transmission Operators (RTO), which basically incorporate the role of European ISO.

(Kwoka, 2002):

$$EVI = [C(Y_G, 0) + C(0, Y_T) - C(Y_G, Y_T)]/[C(Y_G, 0) + C(0, Y_T)]. \quad (2)$$

By exploiting vertical economies of scope, electricity utilities may obtain benefits for various reasons. In general, the complexity of the electricity sector and its interdependency among the different supply stages require a high degree of coordination. In particular, integrated utilities may reduce their costs by coordinating dispatches of utilities' plants according to the actual merit order.[10] Those vertical synergies may be lost with transmission unbundling and, hence, uncoordinated dispatches may shift costs closer to the more expensive reserve power. Besides optimizing economic dispatch of generating plants, Arocena et al. (2012) highlight coordination advantages from efficient plant investment, planning of maintenance schedules, maintenance of spinning reserves,[11] and risk management.

Additionally, Baumol et al. (1982) point out that firms may save on costs by sharing common inputs among different stages of operations. It is most likely that electricity utilities may reduce costs by sharing capital and labor among the supply stages generation and transmission. Additionally, coordination advantages may arise due to technological interdependency of the operational stages of electricity supply (Gugler et al., 2013). Immediate coordination is required in so far as demand has to meet supply at all times. For this instance, the operational stages of electricity supply are interdependent and require informational transactions. "Since the strongest interaction occurs between generation and transmission, one would expect the most significant synergies between these stages" (Meyer, 2012a, p. 97). Other synergies may stem from sharing common production or maintenance tasks, and from the common usage of buildings, administrative staff, or IT software. Another source of vertical synergies may arise from efficient planning of investments by sharing accurate information among the various operational stages. Given these possibilities for attaining vertical economies of integration, their loss from ownership unbundling of the transmission grid may increase the costs of utilities substantially.[12]

4. Model specification and estimation strategy

This study incorporates the quadratic specification of the cost function, which has been introduced by Baumol et al. (1982) and has since been widely applied for estimating scope economies in electricity markets. It provides several advantages over other specifications.

[10] In order to ensure equality of electricity supply when demand is declining, electricity plants may be dispatched from the network according to the merit order, which represents the short-term supply curve of electricity production based on ascending order of power plants' marginal costs.

[11] The spinning reserve is the capacity reserve provided by the generating units actually connected to the power grid. In contrast, generating units not connected to the grid contribute to the non-spinning reserve.

[12] Notwithstanding the synergy losses associated with vertical divestiture, Meyer (2012b) argues that firms subject to ownership unbundling would restructure their organizational form in order to obtain specialization advantages. Moreover, these costs have to be balanced against advantages of potentially increased competition.

Firstly, compared to the translog cost function, the quadratic readily handles the zero-values problem (Jara-Díaz et al., 2004). In the case of estimating vertical scope economies, this problem becomes particularly severe because, by definition, specialized production of one output requires zero values for the other output(s).[13] However, the quadratic cost function represents a second order Taylor approximation of its true unknown form. Hence, its corners may be poorly estimated and should be interpreted with caution. Secondly, against the zero values problem, the quadratic is regarded as relevant for the estimation of cost savings from vertical integration (e.g. Farsi et al., 2008; Farsi and Filippini, 2004) and given its prevalent application, results obtained from a quadratic cost function allow for a direct comparison with other studies.

Many other empirical studies on economies of vertical integration base their analyses on the estimation of a *reduced form* of the full specification of the cost function and/or do not impose all relevant restrictions (Farsi and Filippini, 2004; Fetz and Filippini, 2010; Kwoka, 2002; Meyer, 2012a, 2012b; Nemoto and Goto, 2004). The large estimates of cost synergies in previous papers (as mentioned in Section 2) may partly be due to the fact that "the cost function is not completely specified, as the input cost-share equations are not estimated together with the cost equation, many price interaction terms are excluded, and linear homogeneity restrictions are not imposed" (Arocena et al., 2012, p. 439).

We therefore estimate the *full specification* of the cost function, which includes a full set of interaction terms between outputs and input prices:

$$\begin{aligned} C_{it} = {} & \alpha_0 + \alpha_G + \alpha_T + \sum_j \beta_j Y_{it}^j + 0.5 \sum_j \sum_k \beta_{jk} Y_{it}^j Y_{it}^k + \sum_l \gamma_l w_{it}^l \\ & + 0.5 \sum_l \sum_m \gamma_{lm} w_{it}^l w_{it}^m + \sum_j \sum_l \delta_{jl} Y_{it}^j w_{it}^l + \rho' Z_{it} + \varepsilon_{it} \end{aligned} \tag{3}$$

The subscripts i and t stand for the utility and year, respectively. The dependent variable (C) represents the total costs, Y includes measures for outputs, w stands for measures for input prices, Z is a set of cost shifting variables, and ε is the error term. The two outputs of generation and transmission are given by $j = \{G, T\}$, the three input prices of labor, capital, and fuel are given by $l = \{L, C, F\}$. The constants for overall operations, generation-specific operations, and transmission-specific operations are represented by α_0, α_G andα_T, respectively.

The constant α_0 represents the joint fixed costs of an integrated utility, which operates at both stages of generation and transmission. These may arise, for example, from the usage of common facilities or common staff. Kwoka (2002, p. 659) mentions that "α_0 represents the costs of any indivisible input, costs that would be duplicated by separate

[13] Pulley and Braunstein (1992, p. 223) mention that "(…) the estimated translog cost function cannot be used to measure the costs of specialized production, as is required to estimate economies of scope or product-specific economies of scale." Even though some studies (e.g. Hayashi et al., 1997) try to overcome this dilemma by replacing zero values by an arbitrarily small value, Triebs et al. (2016) argue that such estimates of scope economies may suffer from significant bias. Other functional forms, for example the composite cost function, allow for zero values in outputs (Fraquelli et al., 2005) but bear disadvantages, such as highly non-linear parameters and no economic meaning of coefficients (Triebs et al., 2016).

production (...).” In contrast, α_G and α_T are fixed costs of stand-alone provision of the supply stages of generation and transmission, respectively. The estimated parameter on the output interaction between generation and transmission, β_{GT}, is of particular interest. A negative sign indicates variable cost synergies associated with the joint operation of generation and transmission within one electricity utility relative to separated operations.

Sheppard's Lemma is applied in order to enhance the performance of the regression by estimating the cost function together with its input shares (Christensen and Green, 1978).[14] This imposes no additional parameters but increases the degrees of freedom of the model (Martínez-Budría et al., 2003). The input shares read as follows:

$$\frac{\partial C_{it}}{\partial w_{it}^{l}} = x_l = \gamma_l + \sum_m \gamma_{lm} w_{it}^{m} + \sum_j \delta_{jl} Y_{it}^{j} + \varepsilon_{it}^{l} \tag{4}$$

where x_l represents the quantity of input l, and ε^l is the corresponding error term.

Moreover, we introduce several restrictions to meet the assumptions of a standard cost function. A well-behaved cost function assumes *linear homogeneity* in input prices, so that an increase in input prices proportionally increases total costs. This condition is imposed by dividing total costs and input prices by an arbitrarily chosen input price.[15] Furthermore, we assume symmetry for the β, γ and δ parameters, so that $\beta_{jk} = \beta_{kj}$, $\gamma_{lm} = \gamma_{ml}$ and $\delta_{jl} = \delta_{lj}$. Additionally, we assume cost minimization of utilities and that outputs and input prices are determined exogenously. For the latter, Arocena et al. (2012) state that: “factor prices are determined in competitive markets or through regulation, while electricity output is determined by consumer demand” (Arocena et al., 2012, p. 444). Electricity utilities' inputs, like capital and fuel (uranium, coal, gas, oil) are generally traded internationally, which may support the exogeneity assumption.[16]

5. Data

This analysis utilizes a novel dataset of European electricity utilities. We focus on major utilities in order to ensure some degree of homogeneity. Foremost, contrary to small operators, large utilities are more likely to incorporate a transmission grid if vertically integrated. Data are collected from the firms' annual reports and are combined with other sources (Platts, Orbis, Worldscope, Eurostat, OECD). Limitations on data availability of relevant variables eventually led to the utilization of data from 28 major European electricity utilities from 16 European countries for the period 2000–2010.

[14] Note that it is necessary to drop the input share equation regarding the input price which is used for normalization of costs and input prices.

[15] In our case, we divide costs and input prices by the price of fuel.

[16] In contrast, labor is rather nationally determined. Besides, the exogeneity assumption may not hold if, for example, large operators may obtain inputs in large amounts at cheaper prices, which might bias our empirical estimates in the direction of high EVI. Hence, we ran a robustness regression for a subsample of utilities that have shares of generation capacities from fuelless technologies (i.e. wind, solar, hydro) above the mean. Robustness is confirmed in so far as the coefficient estimate of the output interaction term is negative and significant. We thank an anonymous referee for raising these points.

The utilities in our sample cover 74% in total load of their respective countries.[17] Some missing values in the data emanate from a lack of information in the respective annual reports or from other data sources.[18] Hence, the sample is structured as an unbalanced panel. When possible and reasonable, single missing observations were inter- or extrapolated.[19] Despite potential measurement errors in the data, we are quite confident that these do not systematically correlate with firm integration of interest (which would systematically bias our estimates). In total, the sample comprises 242 observations. Summary statistics for all variables employed in this analysis are provided in Table 1.[20] The sample includes all organizational company structures of pure generators, pure transmission operators, and vertically integrated utilities. Appendix Table A1 provides an overview of the electricity utilities covered by the sample.

5.1. Dependent variable

The dependent variable, total costs, represents the sum of capital and operating expenditures. One particular concern regarding the estimation of multistage cost functions is to avoid any potential double-counting of expenses for purchased electricity (e.g. Kwoka, 2002; Jara-Díaz et al., 2004; Meyer, 2012a, 2012b). Expenditures for purchased electricity have to be excluded from the total costs of utilities, which obtain all or a part of their electricity from external sources. Kaserman and Mayo (1991) have neglected to subtract purchased powers from total costs in their seminal paper, and have consequently been largely criticized by successive works.[21] Unfortunately, data on *expenses* on purchased power were largely not available. For that reason, we collected data on the *amount* of purchased power from annual reports of the utilities in our sample. The amount of purchased power was then multiplied by the spot market price of electricity, obtained from the European Energy Exchange for the respective years. This made it possible to exclude purchased power from total costs.[22]

5.2. Output variables

The upstream *generation output* is measured as the *amount of electricity* (in TWh). Even though some utilities operate at the national level only, others possess generation

[17] The comparison is based on OECD data on total national load for the available period 2003–2010: 2003: 69%, 2004: 70%, 2005: 79%, 2006: 76%, 2007: 75%, 2008: 74%, 2009: 76%, 2010: 74%; Switzerland was excluded because of missing data.

[18] Due to missing information regarding our output measures we were not able to include some important utilities like E.ON.

[19] Inter- and extrapolations of individual data points make up around 4% in total data points.

[20] The variables $d\_patents$, $trend$, $1 - HHI$ and $rnwbl$ will be explained in more detail in Section 5, where we investigate the potential sources of vertical economies of scope.

[21] See Kwoka (2002, p. 659f) for a discussion.

[22] To check for robustness, we ran all regressions presented in this paper without subtracting purchased power from total costs. Regression results hardly changed. This is especially true for the parameter of interest on the output interaction term (β_{GT}). Hence, the exclusion of purchased power seems less problematic in our analysis than in other studies. One explanation may be that we focus on transmission unbundling, whereas the main body of the literature concentrates on distribution unbundling.

Table 1
Sample statistics.

Description	Variable	Main sources	Obs.	Mean	S.D.	Min.	Max.
Dependent variable							
TOTEX excl. purchased power (htEUR)	C	Worldscope; Orbis; annual reports	242	73.61	118.83	1.20	578.98
Outputs							
Generation (TWh)	Y_G	Annual reports	242	74.80	136.85	0.00	669.00
Transmission (tkm)	Y_T	Annual reports	242	9.80	21.65	0.00	100.69
Input prices							
Price of labor (tEUR/empl.)	w_L	Worldscope; Orbis; annual reports	242	57.69	21.53	12.07	141.01
Price of natural gas (tEUR/GWh)	w_F	OECD observer	242	26.03	8.55	9.75	44.78
Price of capital (%)	w_C	Worldscope; Orbis; annual reports	242	7.05	3.77	0.68	30.32
Other control variables							
Share hydro capacity (%)	hyd	Platts PowerVision	242	28.28	26.63	0.00	100.00
Share nuclear capacity (%)	nuc	Platts PowerVision	242	11.77	17.10	0.00	61.46
Binary indicator: generation only	α_G		242	0.43	0.50	0.00	1.00
Binary indicator: transmission only	α_T		242	0.12	0.33	0.00	1.00
Sources of vertical economies							
Binary indicator: registered patents	$d\_patents$	Orbis	242	0.44	0.50	0.00	1.00
Yearly time trend	$trend$		242	5.74	3.01	0.00	10.00
Share of renewable energy supply	$rnwbl$	Eurostat	224	0.11	0.10	0.01	0.46
Plant concentration index	HHI^{plant}	Platts PowerVision	242	0.03	0.04	0.01	0.25
Firm concentration index	HHI^{firm}	Platts PowerVision	242	0.27	0.24	0.09	1.00

Notes: Obs. refers to utility-year observations, S.D. is standard deviation, Min. is minimum, Max. is maximum, htEUR is hundred thousand (10^8) EUR, tEUR is thousand EUR, tkm is thousand km, TWh is thousand GWh.

plants across countries. If an electricity utility is found to operate overseas (outside Europe), it was generally possible to obtain the amount of electricity produced in Europe.

We employ the *length of the transmission grid* (in kilometers) as a measure of the *transmission output*.[23] This may seem controversial at first, but bears some advantages over a more conventional measure, such as transmitted volumes. Notably, the transmission grid is capital intensive and costs hardly change with variations in transmitted volumes, in particular in the short run. Thus, contrary to transmitted volumes, the length of the transmission grid may be more accurate in capturing capital expenditures. Moreover, the length of the grid (besides other factors such as topography or underground cabling) is crucial for maintenance expenditures and thus may have an influence on operating expen-

[23] In the fashion of Triebs et al. (2016), we chose a single output measure (because of multi-collinearity issues) for the downstream transmission stage among several possibilities, such as transmission grid length, transmitted volumes, or peak grid-load.

ditures. Another argument for measuring the transmission output variable in kilometers (rather than in TWh) is based on the fact that transmitted volumes may not be under the immediate control of transmission grid operators, while the lengths of the transmission lines are. Because of the laws of physics, electricity cannot be easily transmitted directly from one location to another, but rather flows through its way of least resistance – often via detours (called loop flows[24]) which are not subject to utilities' influence.

5.3. Input price variables

Among the input-price variables, we include the price of labor, the price of capital, and the price of fuel. The price of labor is calculated as the expenses on salaries per year divided by the number of employees and, thus, represents the average expenses per employee per year. The data are obtained from Worldscope and are supplemented and, in case of doubtful values, verified by data from Orbis or annual reports.

For the calculation of the price of capital we face one caveat. Generally, the annual rental rate of capital would represent a plausible measure. Nevertheless, we do not have such information for our sample. Therefore, we approximate this variable by the interest expenditures on long-term debt relative to long-term debt. Evidently, long-term debt represents the most important source of funds for a capital intensive industry like electricity.[25] The data come from Worldscope and are backed by Orbis und annual reports.

The price of fossil fuel is approximated by the annual average national price of natural gas for industrial customers obtained from OECD.[26] The utility's respective gas price was taken from the country of its headquarter. This seems plausible because most utilities in the sample operate to a large scale at the national level. Similarly, other studies have included the price of fossil fuel, generally approximated by the price of natural gas (e.g. Martínez-Budría et al., 2003; Jara-Díaz et al., 2004). Apart from fossil sources, other generation technologies, such as nuclear energy, water or other renewables, have very low or even zero fuel costs.[27]

5.4. Control variables and identification

We employ the *share of hydro* (*hyd*) and the *share of nuclear power* (*nuc*) in total installed capacity per utility obtained from Platts PowerVision, in order to control for

[24] In general, loop flows play a minor role in the distribution network.

[25] In a similar vein, Kaserman and Mayo (1991) employ the yield to maturity on long-term bonds as their price of capital, and Triebs et al. (2016) also concentrate on long-term interest rates for calculating capital expenditures.

[26] Unfortunately, the gas price explicitly for *electricity companies* in the OECD database exhibited too many missing values and could therefore not be employed in this analysis. However, both variables (i.e. the gas price for industrial customers and for electricity companies) reveal a high correlation of 0.998.

[27] The OECD Observer states that "unlike for coal, oil and gas, the impact on final prices of nuclear energy is very limited because fuel costs account for only 5% of the production cost." (OECD Observer No. 249, May 2005, http://www.oecdobserver.org/news/archivestory.php/aid/1595/Uranium__price__hike__.html, accessed 11 June, 2014).

different generation techniques. Hydro and nuclear power exhibit low marginal costs and are therefore likely to serve as cost shifters. We expect a negative impact on total costs.

One decisive feature of this study is its sample of electricity utilities across European countries over time. Consequently, the panel structure allows employing fixed effects estimation in order to check for unobserved heterogeneity. *Time fixed-effects* are introduced to capture, for example, technological progress in the industry or other shocks such as demand variations (e.g. through the financial crisis) common to all utilities in the sample. We include *country fixed-effects* to capture systematic time-invariant differences across the 16 countries due to, for example, different regulatory regimes, climate conditions, which may determine demand for electricity, topography, relevant for the costs of constructing and maintaining the transmission grid, or production possibilities (e.g. availability of rivers for hydro power plants).

Since, a great share of variation in our sample is cross-sectional this may preclude identifying the EVI using within-utility variation. Therefore, our strategy to arrive at a credible (cross-sectional) identification strategy is threefold. First, we try to control for a lot of possible confounding factors (input prices; share of hydro; share of nuclear; time-fixed effects; country fixed effects). In that respect, we view the 16 country fixed effects for 28 firms particularly relevant to control for confounding effects. Second, we estimate a full specification of the cost function (including interaction terms between outputs and input prices), again going a long way towards eliminating confounding effects. Finally, in Section 7 we look at the sources of vertical economies including double interaction terms (with patents, a time trend, share of renewables and HHI).

5.5. General data issues

Financial variables, such as the total costs, salaries, or debt are obtained either from Worldscope for utilities listed on a stock exchange or from Orbis if not listed. Both sources provide data at the firm level. Accordingly, all global activities are captured if a firm operates overseas. This bears problems, since our output variables are measured at the European level.[28] For those utilities it was necessary to adjust their financial variables to European activities. Hence, we calculated the annual *share of sales in Europe in total (global) sales* for each firm that operated overseas and adjusted the financial variables accordingly.

Another data issue concerns the product mix of our sample utilities. Many electricity companies do not only provide a single product (electricity) but also engage in other production segments, foremost gas (but also water, waste, etc.). In order to limit our study to the analysis of *electricity*, it was necessary to adjust for firms' operations apart from electricity. Henceforth, we calculated the *share of revenues from electricity in total revenues (*i.e. *revenues generated from the whole product mix)*[29] and proportionally ad-

[28] Of course, this is equal to the national level for utilities operating only within one country.
[29] On average, the share of revenues from electricity in total revenues is 89.3%.

justed all financial variables based on the share of revenues from electricity. Worldscope and Orbis provide their financial data on various operational segments (e.g. electricity). Moreover we checked for robustness with information from annual reports (and other external sources) when data were available.

6. Results

This section provides regression estimates of the quadratic cost function as presented in Eqs. (3) and (4). We utilize these estimates to quantify potential cost savings from vertical synergies between the stages of generation and transmission. Different specifications of the model are chosen and discussed against their appropriateness.

6.1. Cost function estimates

As presented in Section 4, we impose linear homogeneity of the cost function and divide the costs and input prices by the price of fuel. Moreover, we apply Sheppard's Lemma to enhance estimation efficiency and estimate Eq. (3) together with the cost share equations (4). In order to meet the non-linear characteristics of our cost function and its input shares, we estimate a non-linear system of equations. Hence, contrary to many other studies which employ a linear estimator of the cost function, we apply non-linear GLS estimation (NLSUR), "which is the non-linear counterpart of Zellner's iterated seemingly unrelated regression technique" (Fraquelli et al., 2005, p. 298).

As stated in the previous section, a particular feature of this analysis is the possibility of estimating a panel regression with fixed effects.[30] Because of the above reasoning, we apply 16 country specific fixed effects and 11 year fixed effects, which may capture unobserved regional (e.g. regulatory regimes, topography, production possibilities) and temporal heterogeneity (e.g. technological progress, demand shocks).

Table 2 shows the regression results from different model specifications. The basic model (Model i) excludes fixed effects, while alternative specifications introduce time fixed effects (Model ii) and country fixed effects (Model iii). Both time and country fixed effects are included in Model (iv).[31] All regressions are estimated with robust clustered (by utility) standard errors. Evidently, the regression estimates are robust to different specifications.[32]

Most importantly, the coefficient estimate on the output interaction term β_{GT} is negative and statistically significant across specifications and its magnitude remains quantitatively similar across the columns. Since, the output interaction term measures cost savings based on the respective output combinations of generation and transmission,

[30] We refer to Greene (2001), who states that fixed-effects estimation with non-linear models is feasible.
[31] The coefficient estimates of the fixed effects are not reported but available upon request.
[32] Table A2 provides robustness estimates based on OLS and linear SUR, which underline the appropriateness of our non-linear SUR results.

Table 2
Non-linear regression (NLSUR) estimates of the cost function.

		(i) Basic model		(ii) Time FE		(iii) Country FE		(iv) Time and Country FE	
G & T	α_0	0.5852	(0.386)	0.9311	(0.459)**	1.0088	(0.731)	0.8026	(0.700)
G only	α_G	−0.1055	(0.342)	0.0385	(0.384)	−0.2736	(0.362)	−0.0071	(0.394)
T only	α_T	2.2536	(0.747)***	2.2903	(0.759)***	3.3830	(0.744)***	3.2382	(0.726)***
Y_G	β_G	0.0351	(0.011)***	0.0333	(0.012)***	0.0596	(0.014)***	0.0585	(0.013)***
Y_T	β_T	−0.1502	(0.059)***	−0.1427	(0.059)**	−0.1318	(0.053)**	−0.1066	(0.055)*
$0.5Y_GY_G$	β_{GG}	0.0001	(0.000)	0.0002	(0.000)	0.0000	(0.000)	0.0000	(0.000)
$0.5Y_TY_T$	β_{TT}	0.0041	(0.002)**	0.0038	(0.002)*	0.0021	(0.002)	0.0014	(0.002)
Y_GY_T	β_{GT}	−0.0006	(0.000)*	−0.0007	(0.000)*	−0.0007	(0.000)**	−0.0008	(0.000)**
P_L	γ_l	0.1789	(0.039)***	0.1858	(0.040)***	0.1679	(0.040)***	0.1760	(0.041)***
P_C	γ_c	0.3116	(0.033)***	0.3230	(0.034)***	0.3092	(0.039)***	0.3189	(0.042)***
$0.5P_LP_L$	γ_{ll}	−0.0078	(0.015)	−0.0110	(0.016)	−0.0045	(0.015)	−0.0085	(0.016)
$0.5P_CP_C$	γ_{cc}	−0.1309	(0.046)***	−0.1308	(0.048)***	−0.1407	(0.049)***	−0.1354	(0.050)***
P_LP_C	γ_{lc}	−0.0161	(0.007)**	−0.0211	(0.006)***	−0.0140	(0.008)*	−0.0191	(0.008)**
Y_GP_L	δ_{Gl}	0.0000	(0.000)	0.0000	(0.000)	0.0000	(0.000)	0.0000	(0.000)
Y_GP_C	δ_{Gc}	−0.0007	(0.000)***	−0.0007	(0.000)***	−0.0006	(0.000)***	−0.0006	(0.000)***
Y_TP_L	δ_{Tl}	0.0006	(0.001)	0.0006	(0.001)	0.0006	(0.001)	0.0005	(0.001)
Y_TP_C	δ_{Tc}	0.0042	(0.001)***	0.0042	(0.001)***	0.0041	(0.001)***	0.0042	(0.001)***
Share hydro cap.	*hyd*	−0.0080	(0.005)	−0.0067	(0.005)	−0.0147	(0.012)	−0.0100	(0.013)
Share nuclear cap.	*nuc*	−0.0063	(0.009)	−0.0053	(0.010)	0.0260	(0.029)	0.0252	(0.030)
Time FE		No		Yes		No		Yes	
Country FE		No		No		Yes		Yes	
Obs.		242		242		242		242	
Overall R2		0.883		0.891		0.928		0.936	

Notes: Dependent variable is total expenditures excluding purchased power; Robust clustered (by utility) standard errors in parentheses; ***, **, * indicate significance at the 1%, 5%, and 10% levels, respectively.

it is of relevance for *variable* EVI. On the other hand, the parameters α_0, α_G, and α_T measure the fixed costs associated with vertical integration, stand-alone generation, and stand-alone transmission, respectively, which are independent of the magnitude of the outputs produced. For an integrated utility α_0 occurs only once, but these fixed costs would be duplicated in case of separated production (which applies to unbundled utilities).

Across specifications, α_0 is statistically insignificant (except for Model ii) indicating negligible fixed cost savings of vertical integration. However, their magnitude has to be calculated according to Eq. (2) based on the estimates from the cost function, as shown in Section 6.2. Moreover, α_G is statistically insignificant throughout, which implies that stand-alone generation is not associated with additional fixed costs compared to vertical integration. On the contrary, the positive and significant coefficient value of α_T indicates additional fixed-costs increases for stand-alone transmitters.

Although not explicitly shown in Table 2, the coefficient estimates of the time fixed effects are largely insignificant, with the exception of significantly negative impacts in the years 2006 and 2007. In contrast, most country fixed effects (10 out of 16 in Model iv) enter statistically significant. There seems to be significant heterogeneity across European countries with respect to the costs of supplying electricity.

6.2. Economies of vertical integration (EVI)

The quantification of vertical economies follows Eq. (2) and is based on estimates from the cost function. Economies of vertical integration reflect the cost savings of joint operation of electricity generation and transmission versus stand-alone operations. Specifically, we calculate the cost savings from joint operation at median and mean output combinations for integrated utilities (reflecting firm size). Given a skewed distribution, there is a great difference between the median and the mean. The median sized integrated firm produces 45.5 TWh electricity and possesses 5500 km of transmission lines, the mean refers to 117.5 TWh and 14,700 km. Independent variables (input prices and control variables) are evaluated at their mean values. To obtain significance levels, we test Eq. (2) against zero based on a non-linear Wald test.[33]

Table 3 reports the magnitude of vertical synergies at median and mean output levels according to Eq. (2) based on the estimates of various specifications of the cost function (as shown in Table 2). Moreover, the overall EVI are decomposed into their fixed and variable components. Overall EVI for the median and mean sized integrated firm are economically and statistically significant across specifications. Only for the case of median EVI based on Model iv (time and country fixed effects), results are close to conventional statistical significance (p-value $= 0.13$, i.e. statistical significance with a probability of 87%).

[33] We use STATA's command *testnl*. The chi-squared values are based on the Delta-Method, which requires a large sample. Alternatively, we apply a linear test of Eq. (1) against zero using STATA's command *lincom*. The significance levels hardly change.

Table 3
Median and mean economies of vertical integration (EVI) for integrated utilities.

	(i) Basic model	(ii) Time FE	(iii) Country FE	(iv) Time and Country FE
Median EVI	17.1%*	21.2%**	16.7%*	14.4%
	(3.00)	(6.08)	(3.03)	(2.28)
... fixed EVI	13.6%	18.1%**	14.1%	11.6%
	(2.22)	(4.84)	(2.50)	(1.65)
... variable EVI	3.5%*	3.2%*	2.6%***	2.8%***
	(2.86)	(2.81)	(9.85)	(10.64)
Mean EVI	24.2%**	27.1%**	22.1%**	21.0%**
	(3.91)	(5.91)	(4.29)	(4.28)
... fixed EVI	8.8%	12.3%**	9.7%	7.8%
	(2.10)	(4.02)	(2.13)	(1.43)
... variable EVI	15.5%*	14.8%*	12.3%***	13.2%***
	(2.90)	(3.00)	(7.76)	(8.57)

Notes: EVIs are calculated for integrated utilities at the mean output combination (G = 117.4 TWh, T = 14.7 tkm) and the median output combination (G = 45.5 TWh, T = 5.5 tkm). Fixed EVI relate to fixed cost savings, variable EVI to variable cost savings. Chi-squared values from a non-linear Wald test are given in parentheses. ***, **, * indicate significance at the 1%, 5%, and 10% levels, respectively.

In general, Table 3 confirms the presence of considerable vertical cost synergies for integrated European electricity utilities. Form our preferred specification (iv) including time and country fixed effects, we estimate vertical cost synergies for the median and mean sized utility of 14% and 21%, respectively, relative to stand-alone operations. Hence, the findings indicate that with larger output combinations, cost savings increase further. From this we argue that large integrated electricity operators may benefit from higher economies of vertical integration that would be lost with ownership unbundling.

The decomposition of EVI into fixed and variable parts is interesting too. The negative and statistically significant coefficient on the output interaction term (β_{GT}) suggests strong evidence for the presence of *variable* cost synergies between the stages of generation and transmission (i.e. cost complementarity). Hence, with larger combinations of *both* outputs (i.e. larger amount of electricity generated and longer length of transmission grid lines), electricity utilities may be able to internalize negative market externalities through better coordination. Variable cost synergies are therefore dependent on the magnitude of the two outputs. This is an explanation, why variable EVI make up a relatively larger proportion of the mean sized integrated utility compared to the relatively smaller median sized utility.

Conversely, fixed EVI are independent of the magnitude of the output level. Fixed costs of joint production would be duplicated in case of vertical separation. However, with increasing scale (i.e. larger output combination) fixed EVI lose in importance relative to variable EVI. Moreover, while the constant on stand-alone generation (α_G) is statistically insignificant (see Table 2), the constant on stand-alone transmission (α_T) is positive and significant. Hence, evidence points to additional fixed costs for transmission companies (in addition to the duplication of overall fixed costs), whereas there are no additional fixed costs for stand-alone generators.

From these findings we can derive important policy implications. The regulatory principle of ownership unbundling of the transmission grid comes at substantial costs due to lost vertical synergies. This finding holds especially true for large scale integrated electricity utilities which may obtain cost advantages of beyond 20%. Hence, countries with large vertically integrated electricity utilities prior to the implementation of ownership unbundling may suffer the most from vertical divestiture. These countries may face severe barriers when introducing transmission unbundling, as such a policy requires its associated benefits (such as increased competition, lower end-consumer prices, etc.) to exceed the associated lost vertical cost synergies. On the contrary, countries with relatively small electricity companies may obtain economic benefits, such as non-discriminatory price competition in the upstream stage of generation, by introducing full ownership unbundling, while the associated losses from vertical economies may be of lesser importance.[34]

7. Sources of vertical economies

So far, the analysis has provided evidence for the existence of scope economies of around 14% for the median integrated firm. For large scale integrated electricity utilities there is even scope for greater cost synergies from vertical integration. This section tries to evaluate empirically where economies of vertical integration may stem from. Besides other potential influential factors, we specifically concentrate on two sources of vertical economies in this empirical investigation: (i) there may exist vertical economies from the presence of *asset specificity.* (ii) There may be *high market complexity* among the supply stages of generation and transmission, which may require *coordination* that an integrated utility can meet at lower costs than leaving coordination to the market.

For both potential explanations for the presence of economies of vertical integration we estimate the cost function as presented in Eq. (2), yet include an additional parameter (θ) on the output interaction term multiplied by the additional variable of interest: $\theta * Y_G Y_T Z$, where Z may represent a proxy for asset specificity or market complexity. *If θ was found to be negative and significant, this would be an indication that vertical integration is cost-beneficial compared to stand-alone operations in order to deal with either asset specificity or market complexity.* In other words, we test for variation in scope economies with different proxies for complexity and asset specificity.[35]

[34] In this context, Meyer (2012b, p. 168) stresses that the actual degree of lost cost synergies from vertical divestiture largely hinges on the effectiveness of a newly created market mechanism that may overtake "firm internal coordination." However, we cannot empirically test for this hypothesis.

[35] In this respect, Forbes and Lederman (2009) focus on vertical integration in the US airline industry, where high market complexity may lead to costly ex-post adaptations and renegotiations with subcontractors. Moreover, the authors provide a short overview about studies that investigate the relationship between asset specificity and vertical integration, which generally find a positive relationship (i.e. asset specificity is associated with higher vertical cost savings).

7.1. Asset specificity

Vertical economies may arise from asset specificity (e.g. Williamson, 1971) in the electricity industry. As noted earlier, the electricity industry is highly complex with specific network characteristics (supply has to meet demand at all times, electricity flows follow physical laws) and requires intensive coordination among the supply stages. Moreover, investments in electricity generation (e.g. building a new power plant) and/or transmission (e.g. extension of the existing grid) are generally associated with sunk costs since their associated value for alternative use is low. At both stages of supply, investments in new power plants or in the transmission grid have no alternative usage other than power generation or power transportation ('site specificity'), are immobile and constructed to operate long-term ('physical asset specificity'), and require specialized human capital, such as plant operators or engineers ('human asset specificity') (Joskow, 2005b). Given their asset specificity, investments in the electricity industry are risky, and hence the 'hold-up risk' of electricity utilities may be minimized by vertical integration (Meyer, 2012b).

A general proxy for asset specificity in any industry is technological intensity. In this sense, Acemoglu et al. (2010) investigate the determinants of vertical integration and find that vertical integration is more likely when the (producing) industry has a higher share of R&D expenditures in value added. Unfortunately, data on R&D expenditures at the firm level provided by Worldscope Datastream exhibit many missing values and generally show little information. Therefore, we try to approximate technological intensity by patent data. We utilize firm-level data on patents from Orbis to create a binary indicator (*d_patents*) which is equal to one if a firm has engaged in research (has registered patents) over the sample period 2000–2010 and zero otherwise. Although this is just a crude measure for technological intensity, we believe that it provides at least some discrimination between technologically more intense firms and others.

7.2. Coordination requirements from market complexity

Over the past two decades, electricity markets have had to deal with several influences for which the network as well as the power plants were initially not designed for. This, in turn, *intensified the complexity* of electricity markets and the corresponding coordination requirements *over time*. For instance, the increased share of vastly intermittent renewables at guaranteed feed-in tariffs have led to market distortions (e.g. replacement of conventional gas and oil plants) and boosted the number of plant dispatches. Moreover, market entry has occurred due to market liberalization policies. In addition, subsidized provision of decentralized (renewable) electricity generation and market coupling have exacerbated complexity in recent years. From this we assume that the multiplication of a time trend over the sample horizon 2000–2010 (*trend*) by the output interaction term may reveal increased coordination requirements over time.

We further investigate the topic of complexity and focus on renewable energy sources. Renewables tend to enhance coordination needs of the electricity system because wind and solar represent decentralized intermittent sources, often at guaranteed feed-in so that they usually generate whenever possible. Hence, when the wind is blowing and/or the sun is shining, other conventional plants (foremost gas and oil) are replaced by renewables. Based on data from Eurostat we calculate countries' shares of renewable energy in thousand tons of oil equivalent (tTOE) in total energy supply in tTOE over time (*rnwbl*).[36] Therefore, we assume that in countries with increased energy supply from renewable sources, coordination requirements rise.

Coordination requirements may also arise at markets that exhibit a low level of market concentration. We are able to measure market concentration either at the firm level or power plant level. We believe that countries with low levels of concentration are associated with higher coordination requirements, since markets become more complex. In contrast, a high level of plant or firm concentration may lower coordination needs because there is less complexity.

Therefore, we calculate Herfindahl–Hischman-Indices (HHI) from data on power plants' installed capacity obtained from Platts PowerVision. The database provides information about installed capacity of virtually all firms and all power plants of European countries. Hence, we are able to calculate both, plants' and utilities' capacity shares relative to total national installed capacity. Eventually, this yields HHI concentration metrics at the plant level (HHI^{plant}) and at the firm level (HHI^{firm}) for each sample utility in its respective country (i.e. headquarter location). HHI specifically calculates the sum of all plants' or firms' squared capacity shares by country. HHI^{plant} represents a country's sum of squared shares of individual plants' installed capacities relative to national total installed capacity per year: $HHI_{c,t}^{plant} = \sum_{p=1}^{N} {a_p}^2$, $a_p = \frac{capacity_{p,c,t}}{\sum_{p=1}^{N} capacity_{p,c,t}}$, where the subscripts p, c, and t stand for plant, country, and year, respectively. HHI^{firm} calculates accordingly: $HHI_{c,t}^{firm} = \sum_{i=1}^{N} {a_i}^2$, $a_i = \frac{capacity_{i,c,t}}{\sum_{i=1}^{N} capacity_{i,c,t}}$, where i denotes the firm. Note that HHI varies between zero and one, where a value of one represents maximum concentration – one plant or one firm owns the entire installed generation capacity in a country. In order to induce the same economic interpretation of the θ-coefficient as above, we subtract HHI from one and multiply it by the output interaction term. Hence, θ measures the impact of $Y_G Y_T (1 - HHI)$ on total costs. A low level of concentration (i.e. a high value of $(1 - HHI)$) may increase the coordination needs of power plants or utilities as the market becomes more complex. A negative coefficient estimate therefore indicates that market complexity from lower plant or firm concentration leads to cost savings from vertical integration.

[36] See http://ec.europa.eu/eurostat/data/database (accessed 17 December, 2014). Please note that Switzerland is not included in Eurostat's database, which results in the loss of 18 observations.

7.3. Results

In Table 1 we present descriptive statistics of the variables used to measure either asset specificity ($d\_patents$) or complexity ($trend$, $rnwbl$, $1 - HHI^{plant}$, $1 - HHI^{firm}$). Each of these variables now enters the econometric estimation of the cost function as a double interaction with the output interaction term. If negative and statistically significant, its coefficient (θ) indicates cost synergies from vertical integration either in the presence of registered patents, in more recent years, when a country has low power-plant or utility concentration, or when the share of renewables is high.

Table 4 reports the regression estimates of the cost function, as introduced in Eqs. (3) and (4), but expanded by an additional double interaction term of the output interaction term multiplied by the additional variable of interest, $Y_G Y_T Z$. Z represents a measure for complexity or asset specificity ($d\_patents$, $trend$, $rnwbl$, $1 - HHI^{plant}$, $1 - HHI^{firm}$) as indicated above and θ represents its coefficient. Indeed, the coefficient estimates of θ are negative across model specifications. This is an indication that asset specificity and market complexity indeed lead to cost advantages from vertical integration. Moreover, Table 4 includes EVI estimates for an integrated firm's median and mean output combinations evaluated at various levels of the variables measuring asset specificity and market complexity. The EVI metrics presented here support the robustness of the main findings presented above.

Specification (i) tests for technological intensity and includes a binary indicator for registered patents multiplied by the output interaction term. The negative and significant estimate of θ implies vertical cost synergies for utilities that engage in research (have registered patents). We infer that this corroborates our assumption that electricity utilities may overcome problems associated with asset specificity by vertical integration. The mean integrated patenting utility observes more than 20% EVI, while the non-patenting integrated utility even shows diseconomies of vertical integration, albeit insignificant.

Specification (ii) includes a time trend in the double interaction term to test for increased market complexity. $\hat{\theta}$ becomes negative and significant. This means that as a consequence of increased complexity of electricity markets over time, utilities benefit from vertical integration.

Specification (iii) addresses this issue in more detail by focusing on the countries' shares of renewable energy. Again, $\hat{\theta}$ becomes significantly negative. Hence, an increasing share of renewable energy in total energy supply seems to intensify the complexity of the electricity system. In order to manage the coordination requirements associated with increased complexity, electricity utilities seem to benefit from vertical integration. If a country moves from the minimum of 1% renewable share to the maximum of 46%, EVI increase from 12.1% to 43.7% for the mean integrated utility.

Specification (iv) addresses the issue of power plant concentration. The negative (though insignificant) coefficient of $\hat{\theta}$ suggests that with lower plant concentration (i.e.

Table 4
Non-linear regression (NLSUR) estimates of the cost function including a double interaction term.

		(i) d_patents		(ii) Trend		(iii) Renewables share		(iv) (1-HHI$^{\text{plant}}$)		(v) (1-HHI$^{\text{firm}}$)	
G & T	α_0	0.5609	(0.381)	0.8214	(0.187)***	0.7674	(0.390)**	0.7738	(0.380)**	0.8807	(0.385)**
G only	α_G	−0.0184	(0.381)	−0.3022	(0.183)*	−0.6082	(0.350)*	−0.2125	(0.367)	−0.4545	(0.329)
T only	α_T	3.0887	(0.883)***	2.5536	(0.410)***	2.8827	(0.797)***	2.4484	(0.762)***	2.4470	(0.733)***
Y_G	β_G	0.0303	(0.011)***	0.0402	(0.005)***	0.0517	(0.011)***	0.0367	(0.014)***	0.0437	(0.012)***
Y_T	β_T	−0.1931	(0.070)***	−0.1770	(0.034)***	−0.1998	(0.070)***	−0.1614	(0.061)***	−0.1714	(0.063)***
$0.5Y_GY_G$	β_{GG}	0.0002	(0.000)*	0.0001	(0.000)	0.0000	(0.000)	0.0001	(0.000)	0.0001	(0.000)
$0.5Y_TY_T$	β_{TT}	0.0053	(0.002)**	0.0051	(0.001)***	0.0057	(0.003)**	0.0045	(0.002)**	0.0049	(0.002)**
Y_GY_T	β_{GT}	0.0026	(0.001)*	−0.0004	(0.000)*	0.0001	(0.001)	0.0104	(0.008)	−0.0003	(0.000)
Y_GY_TZ	θ	−0.0034	(0.002)**	−9.94E−06	(0.000)**	−0.0057	(0.002)***	−0.0112	(0.008)	−0.0006	(0.000)***
P_L	γ_l	0.1693	(0.023)***	0.1703	(0.016)***	0.1674	(0.026)***	0.1698	(0.023)***	0.1703	(0.023)***
P_C	γ_c	0.2715	(0.032)***	0.2742	(0.019)***	0.2950	(0.034)***	0.2725	(0.032)***	0.2741	(0.032)***
$0.5P_LP_L$	γ_{ll}	−0.1044	(0.109)	−0.1089	(0.075)	−0.1071	(0.115)	−0.1066	(0.109)	−0.1098	(0.109)
$0.5P_CP_C$	γ_{cc}	−1.2488	(0.832)	−1.2398	(0.567)**	−1.5730	(0.861)*	−1.2304	(0.829)	−1.2488	(0.831)
P_LP_C	γ_{lc}	−0.1598	(0.204)	−0.1840	(0.121)	−0.1958	(0.211)	−0.1710	(0.201)	−0.1818	(0.200)
Y_GP_L	δ_{Gl}	0.0000	(0.000)	0.0000	(0.000)	0.0000	(0.000)	0.0000	(0.000)	0.0000	(0.000)
Y_GP_C	δ_{Gc}	−0.0007	(0.000)***	−0.0007	(0.000)***	−0.0007	(0.000)***	−0.0007	(0.000)***	−0.0007	(0.000)***
Y_TP_L	δ_{Tl}	0.0007	(0.001)	0.0007	(0.000)*	0.0007	(0.001)	0.0007	(0.001)	0.0007	(0.001)
Y_TP_C	δ_{Tc}	0.0043	(0.001)***	0.0044	(0.001)***	0.0043	(0.001)***	0.0043	(0.001)***	0.0043	(0.001)***
Share hydro	*hyd*	−0.0052	(0.005)	−0.0069	(0.003)**	−0.0043	(0.009)	−0.0066	(0.006)	−0.0082	(0.006)
Share nuclear	*nuc*	0.0031	(0.009)	−0.0081	(0.006)	−0.0126	(0.011)	−0.0062	(0.010)	−0.0107	(0.010)
Obs.		242		242		224		242		242	
Overall R2		0.887		0.887		0.894		0.889		0.889	
Median EVI		d_patents = 0: 10.0%		Year = 2000: 16.6%***		Rnwbl = 0.01: 14.7%*		(1-HHI$^{\text{p}}$) = 0.75: 15.2%*		(1-HHI$^{\text{f}}$) = 0.00: 17.8%**	
						Rnwbl = 0.11: 14.9%*		(1-HHI$^{\text{p}}$) = 0.97: 16.2%**		(1-HHI$^{\text{f}}$) = 0.73: 18.0%**	
		d_patents = 1: 11.4%		Year = 2010: 16.6%***		Rnwbl = 0.46: 15.7%**		(1-HHI$^{\text{p}}$) = 0.99: 16.3%**		(1-HHI$^{\text{f}}$) = 0.91: 18.1%**	
Mean EVI		d_patents = 0: −24.4%		Year = 2000: 19.9%***		Rnwbl = 0.01: 12.1%		(1-HHI$^{\text{p}}$) = 0.75: −12.3%		(1-HHI$^{\text{f}}$) = 0.00: 19.5%**	
						Rnwbl = 0.11: 19.4%*		(1-HHI$^{\text{p}}$) = 0.97: 20.7%**		(1-HHI$^{\text{f}}$) = 0.73: 25.1%***	
		d_patents= 1: 21.5%**		Year = 2010: 21.2%***		Rnwbl = 0.46: 43.7%***		(1-HHI$^{\text{p}}$) = 0.99: 23.3%**		(1-HHI$^{\text{f}}$) = 0.91: 26.4%***	

Notes: Dependent variable is total expenditures excluding purchased power; EVIs are calculated for integrated utilities at the mean output combination ($G = 117.4$ TWh, $T = 14.7$ tkm) and the median output combination ($G = 45.5$ TWh, $T = 5.5$ tkm). Robust and clustered (by utility) standard errors in parentheses; ***, **, * indicate significance at the 1%, 5%, and 10% level respectively.

higher complexity), vertical integration results in lower costs.[37] In other words, utilities can save on costs by being vertically integrated when the market becomes more complex due to lower plant concentration.

In addition to measuring concentration at the *plant level*, we calculate HHIs at the utility level, as presented in specification (v). One would assume that lower concentration among electricity utilities' generation capacity is associated with higher market complexity. Indeed, $\hat{\theta}$ turns out negative and significant, indicating cost savings from vertical integration. If a country moves from a monopoly situation (minimum of $(1 - HHI^{firm}) = 0$) to a fairly unconcentrated situation (maximum of $(1 - HHI^{firm}) = 0.91$), EVI increase from 19.5% to 26.4% for the mean integrated utility. For example, Latvia and France are both highly concentrated with HHIs around 0.9 in 2010. EVIs of integrated utilities in such highly concentrated markets are estimated at 18.1% for the mean size. In contrast, Austria, Germany and the United Kingdom exhibit low levels of market concentration with HHIs around 0.1 in 2010. EVI for the mean sized integrated utility are 26.4% in this case. In general, this points to substantial economies of vertical integration. In particular, large scale operations seem to have even greater potential for EVI when market complexity is high (due to low degrees of integration).

Altogether, there appears to be a vast potential for cost savings from vertical integration in the presence of either asset specificity or market complexity. In both cases, empirical evidence indicates that electricity utilities seem to overcome the resulting problems of intensified coordination requirements by vertical integration among the supply stages of generation and transmission. Large scale integrated utilities seem to have greater potential for cost savings from being vertically integrated.

8. Conclusion and policy implications

The EU has already put unbundling of the transmission grid from other stages of electricity supply into practice. Accordingly, Member States may choose between full ownership unbundling and the implementation of an ISO or ITO, where the first is the predominant form in Europe. The reason for transmission unbundling is the hope of increased competitive pressure in electricity generation, caused by a separation from the transmission stage, which is associated with a natural monopoly. However, the potentially positive effects of transmission unbundling may be compensated or even offset by lost synergy effects.

The policy debate on transmission unbundling generally neglects the fact that the benefits of increased competition in the upstream stage of generation in the electricity sector come at the cost of destructing vertical synergies. One reason may be the absence

[37] Lower plant concentration decreases the HHI, so that (1-HHI) increases. This implies that a negative estimate of $\hat{\theta}$ corresponds with cost savings from lower plant concentration.

of thorough empirical evidence for Europe. From this point, this analysis is, to the best of our knowledge, the first to provide European cross-country evidence on the costs of ownership unbundling of the transmission grid.

Cost savings from vertical integration of generation and transmission are likely to arise from various effects. Among them are the common usage of inputs, such as capital and labor. Besides, sharing of information and risk, internalization of externalities, and coordination advantages are reasonable explanations for cost savings. Hence, ownership unbundling of the transmission grid may result in significantly higher costs for electricity utilities.

This study implements novel firm-level data on 28 major European electricity utilities from 16 European countries over the period 2000–2010. Data emanate from annual reports as well as Worldscope Datastream, Orbis, Platts PowerVision, Eurostat, and OECD. Based on the empirical estimation of a quadratic cost function, we quantify vertical economies of scope. Contrary to many other related studies, we introduce a fully specified cost function (including a full set of output and input price interaction terms) together with its input share equations (Sheppard's Lemma) and all standard assumptions (i.e. linear homogeneity in input prices and symmetry in parameters). In order to meet the non-linearity characteristics of the system of equations, we apply a non-linear GLS estimator (NLSUR). One decisive feature of this paper is the possibility to account for unobserved heterogeneity through time and country fixed-effects.

Our results confirm that there are substantial scope economies between the stages of upstream generation and downstream transmission in Europe. For the median integrated utility in our sample, we find cost savings from vertical integration of around 14%. Higher cost savings may be achieved with increased firm size. Large scale utilities may decrease total costs by more than 20% from vertical integration. This scale effect is explained by severe *variable* cost synergies, which are found to be economically and statistically significant across specifications. Overall, the results are robust to various specifications.

Moreover, we subject potential sources of vertical cost synergies to empirical scrutiny. Both, asset specificity of investments in the electricity sector and high market complexity would represent potential sources of vertical synergies that may be addressed by vertical integration. We apply a crude measure of registered patents for technological intensity, which is generally used to approximate asset specificity. Evidence shows that electricity utilities overcome the hold-up risk associated with asset specificity by vertical integration. Market complexity is measured by four alternating variables: a time trend captures, among other factors, increased complexity through electricity production from renewables and market coupling; The share of renewable energy in total energy supply may explicitly measure complexity through renewables' intermittent nature; A power plant concentration index may directly measure coordination requirements; In a similar vein, a firm concentration index captures coordination needs. Evidence shows that vertical integration is cost-beneficial when market complexity is intensified, as coordination requirements can be met easier. Moreover, EVI estimates show that large-scale utilities have greater potential for cost savings from vertical integration.

One should keep in mind, however, that this analysis has a rather static focus because the data at hand do not allow for a proficient analysis of dynamic effects. Over time, cost increases may be partly compensated by positive dynamic effects of unbundling.[38] Besides, the estimated additional costs of ownership unbundling through lost vertical synergies cannot be easily compared with the benefits of increased competition. Yet, this analysis represents an important contribution to the literature and the general debate on unbundling as it provides evidence that transmission ownership unbundling comes at a cost.

Our findings thus call for special caution when arguing about policies furthering unbundling policies in the European Union. In order to overcome efficiency losses from unbundling, market forces may be fostered. From our analysis, it seems that policies that allow for the internalization of externalities from asset specificity and market complexity may be desirable. Particularly, such policies may concentrate on lowering the hold-up risk of sunk costs and enhancing the integration of renewable sources of energy. Moreover, a high quality of market institutions is necessary to meet the inherent coordination needs among the different electricity supply stages.

In sum, the evidence from this analysis aids our understanding of the cost effects of transmission unbundling in electricity. From a policy perspective, a successful unbundling regime would at least require that the benefits of increased competition in power generation would offset the associated efficiency losses from vertical divestiture. Fourteen percent for the median and more than twenty percent for the mean firm therefore represent non-negligible hurdles.

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[38] Schober (2013) provides a comparison of static versus dynamic effects of distribution unbundling. He finds that negative static effects from ownership unbundling and third party access are eventually offset by positive dynamic effects.

Appendix

Table A1
Sample of electricity utilities.

Utility	Country	Obs.	Period	Organizational structure
EVN	Austria	11	2000–2010	G
Verbund	Austria	11	2000–2010	G&T
Wiener Stadtwerke	Austria	3	2008–2010	G
CEZ Group	Czech Rep.	11	2000–2010	G&T until 2002, then G
Fortum	Finland	10	2001–2010	G
EDF	France	11	2000–2010	G&T
ENBW	Germany	10	2001–2010	G&T
RWE	Germany	11	2000–2010	G&T
Public Power Corp.	Greece	11	2000–2010	G&T
Magyar Villamos	Hungary	7	2003–2010	G&T
A2A	Italy	7	2004–2010	G
Acea	Italy	11	2000–2010	G&T until 2005, then G
Enel	Italy	6	2005–2010	G
IREN	Italy	11	2000–2010	G&T
Terna	Italy	10	2001–2010	T
Latvenergo	Latvia	5	2006–2010	G&T
Statkraft	Norway	5	2006–2010	G
Enea	Poland	3	2008–2010	G
PGE Polska Grupa	Poland	3	2008–2010	G
EDP	Portugal	10	2001–2010	G&T
Endesa	Spain	11	2000–2010	G
Iberdrola	Spain	9	2002–2010	G
Red Electrica	Spain	8	2003–2010	T
Vattenfall	Sweden	10	2001–2010	G&T until 2009, then G
BKW	Switzerland	11	2000–2010	G&T
Energiedienst	Switzerland	7	2004–2010	G&T
Drax Group	United Kingdom	8	2003–2010	G
National Grid	United Kingdom	11	2000–2010	T
Total		*242*		

Notes: Obs. is observations; G&T represents an integrated utility, G is stand-alone generation, T is stand-alone transmission.

Table A2.
Robustness: linear regression estimates.

		(A1) OLS		(A2) linear SUR	
G & T	α_0	0.640	(0.434)	0.570	(0.352)
G only	α_G	−0.211	(0.305)	−0.311	(0.285)
T only	α_T	3.079	(0.618)***	2.746	(0.565)***
Y_G	β_G	0.034	(0.006)***	0.035	(0.005)***
Y_T	β_T	−0.184	(0.044)***	−0.175	(0.040)***
$0.5Y_GY_G$	β_{GG}	0.000	(0.000)	0.000	(0.000)*
$0.5Y_TY_T$	β_{TT}	0.005	(0.001)***	0.005	(0.001)***
Y_GY_T	β_{GT}	−0.001	(0.000)***	−0.001	(0.000)***
P_L	γ_l	0.067	(0.172)	−0.007	(0.107)
P_C	γ_c	−1.305	(0.979)	−0.416	(0.458)
$0.5P_LP_L$	γ_{ll}	−14.366	(31.973)	−0.011	(0.008)
$0.5P_CP_C$	γ_{cc}	−23.485	(654.353)	−0.123	(0.045)***
P_LP_C	γ_{lc}	57.022	(146.035)	−0.011	(0.034)
Y_GP_L	δ_{Gl}	0.054	(0.035)	0.070	(0.015)***
Y_GP_C	δ_{Gc}	0.127	(0.175)	−0.001	(0.000)***
Y_TP_L	δ_{Tl}	0.004	(0.191)	0.076	(0.081)
Y_TP_C	δ_{Tc}	0.271	(0.890)	0.004	(0.001)***
Obs.		242		242	
Adj. R2		0.889		0.895	
Median EVI		15.3%**		15.5%**	
Mean EVI		19.6%***		20.2%***	

Notes: Dependent variable is total expenditures excluding purchased power; EVIs are calculated for integrated utilities at the mean output combination ($G = 117.4$ TWh, $T = 14.7$ tkm) and the median output combination ($G = 45.5$ TWh, $T = 5.5$ tkm). ***, **, * indicate significance at the 1%, 5%, and 10% levels, respectively.

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