Convenience yields in the European electricity market

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Abstract

This paper examines the convenience yield in electricity and shows that although non-storable, a storability option exists in the form of installed capacity of power companies. Companies invest in reserve capacity as an alternative to store electricity and capture the benefit of excessive spot price increases (price spikes) at short intervals. We argue that this benefit is equivalent to convenience yield similar to a real option embodied in the electricity markets. Fourteen companies with about 50% of the European electricity market comprise our sample in the period 2004-2011. Estimates on price volatility, capacity and asset utilization are regressed to explain the variation in company ROA taking into account the company and time variation. Estimation results are in line with theoretical predictions of monopoly power and asset utilization and show that a significant part of the profitability of power companies is due to convenience yield. Results show that convenience yields exist even after the increased use of renewable energy which, because of preferential treatment, it tends to reduce the occurrence of price spikes, the main factor that creates convenience yields.

JJEL classification: *G13, G14, G15.*
Keywords: Convenience yield; electricity market, electricity futures, electricity reserve capacity, ROA

INTRODUCTION

The issue of convenience yield has long been a popular subject in the commodities literature (Kaldor (1939), Working (1949), Brennan (1958), Telser (1958), Fama and French (1987), Henkel, Howe and Hughes (1990), Brennan (1991), Milonas and Thomadakis (1997a, 1997b), Milonas and Henker (2001), and Heaney (2002)). Convenience yield arises in storable commodities and at times of insufficient inventories. When demand is inelastic, scarce supplies push spot prices over futures prices rendering a benefit to holders of inventories. The difference of spot and futures price, after accommodating for the carrying charges, is what is called convenience yield.

Among the commodities with continuous growth and importance over the last 30 years, energy commodities are at center stage. Energy products can be used either as a final product to run engines or can be converted to electricity in power plants. During the power generation process, the embedded value of fuels including their convenience yields is transferred into the value of the end product, that is, into electricity prices. If this were not the case, the value of energy products should be unrelated to electricity prices. Besides, if convenience yields were not transferable to the value of the end products, the transformation would not be chosen in a free market, since energy fuels are storable and their embedded values can be carried into another period for a higher reward. As a result, it can be argued that electricity prices incorporate the convenience yields of inputs although electricity itself, once produced, cannot be stored for future use.

The non-storable nature of electricity led many authors to argue that electricity prices are not driven by the cost-of-carry necessities since the implied arbitrage arguments are not applicable.[1] Yet, recent work has provided evidence that electricity prices behave in line with the level of fuel supplies. For example, Douglas and Popova (2008) identified the natural gas inventories as a determinant of the risk premium in electricity futures markets. Botterud, Kristiansen and Ilic (2010) studied hydro power plants in Norway and identified the effect of the level of water reserves on spot and electricity futures prices resulting in an estimate of convenience yield in electricity prices. Most recently, Paratsiokas and Milonas (2014) provided a model in which electricity prices reflect the convenience yield embodied in the prices of the fuel used.

In this paper we attempt to identify convenience yields in yet another aspect of the electricity market: the installed capacity of power companies. Power companies invest in capacity to respond to short-term excess demand for energy. This strategy aims at capturing the benefit of

[1] See Eydeland and Geman (1998), Bessembinder and Lemmon (2002), Lucia and Schwartz (2002) and Pirrong and Jermakyan (2008).

excessive spot price increases, known as price spikes, at short time intervals. We argue that this benefit is equivalent to convenience yield embodied in the electricity markets.

As with all corporate establishments, the value of a power company is made up of the present value of its future cash flows. Most of the cash flows are derived from producing electricity in the normal course of production under normal demand and supply conditions. However, a part of the cash flows (payoffs) is not derived from the company's continuous business but from exercising the options available to the company known as real assets (expansion, contraction, investment delays, etc.). We argue that access to convenience yield represents such a real asset.

Because electricity is not storable, power companies choose to invest in reserve capacity as an alternative to storing electricity. This capacity, depending on the type of the generation technology concerned, remains idle for most of the time and serves as an insurance against the risk of power system failures and blackouts. At times of excessive demand (summer heat, winter cold), power companies operate their facilities to meet system requirements but also operate the reserve facilities to capture the reward of price spikes. In doing so, power companies sell electricity at a higher price than the real marginal production cost. This action is similar to the exercise of a call option. In this case the contingent claim is a "real option" and embeds a claim to the convenience yield embodied in 'stored' capacity.

Our testable hypothesis is that installed capacity embodies a contingent claim. If this is the case, the return that power companies earn should relate positively to price volatility. Furthermore, power companies with large capacities should obtain higher values than similar power companies with relatively small capacities in high volatility periods.

As mentioned above, to respond to the need of great demand for electricity, power producers need to invest into capacity both in terms of stored "fuel" and in terms of fixed assets for power generation. Such investment is put to work based on the dispatching schedule and its goal is to match the supply of electricity with demand needs. When demand for electricity is high and electricity prices exceed normal levels and even turn into spikes, the value of the 'real option' is greater. As a result, investment in 'stored' capacity becomes the vehicle for obtaining the convenience yield at times of electricity shortages. If such shortages do not arise, the value of 'stored' capacity is bound to be rather small but always nonzero. Table 1 summarizes the relationships between the value and the return on capacity at times of normal and extreme demand for electricity.

Table 1
The predicted effect of demand and stored capacity on asset returns

Demand Condition	'Stored' Capacity	Value on 'stored' Capacity	Return on 'Stored' Capacity
Normal	Unused	Small	Zero
Extremely high	Put to use	Large	High

The rest of the paper is organized as follows: Section II presents the state of the European electricity markets, highlighting how the changing conditions in electricity markets may affect firm investment decisions. Section III presents the electricity market structure of companies and countries in the European Union as evidenced from the mix of fuels, market share, electricity generation and profitability. Section IV develops the methodology and the model that will be used. Section V describes and analyzes the data characteristics. Section VI, discusses the results of the empirical analysis and their implications. Some concluding remarks are offered in the final section VII.

I. THE STATE OF THE EUROPEAN ELECTRICITY MARKET

During the era of regulation of electricity markets, power plants were required to maintain excess capacity in order to accommodate situations of excess demand. Electricity prices were regulated to the point where electricity firms would earn a rate of return sufficient to cover their costs. Since then, electricity markets have been de-regulated and wholesale prices vary by the demand and supply of electricity every single hour. Power plants produce the electricity they wish but sell it through the national transmission network whose operator attempts to balance the volume of electricity demanded at each single period to the available electricity. It comes as no surprise that the price of electricity becomes the balancing factor in the market at each single period.

For a power transmission system to work efficiently and to avoid blackouts and other disturbances there must be excess capacity available. This capacity can be obtained through connections with systems of neighboring countries or through extra capacity in domestic power plants. It is the latter that is of interest in this research.

According to classical economic theory, every investment is undertaken, if its returns cover costs. The occurrence of price spikes has enabled companies to undertake redundant investments in power facilities for only occasional utilization. The expected convenience yield enters economic calculations as a positive payoff, and can turn negative net present value projects into positive and acceptable projects.

Major recent developments in the power market include the introduction of new technologies in producing electricity from renewable energy sources (RES). These developments affect the investment calculus for traditional production capacity.

More specifically, in the European Union and in order to promote the use of energy from RES and reduce carbon emissions, many countries have established subsidies for investment outlays required by the RES technology and/or the price paid for each kWh. As a result, RES technologies have received a boost resulting in a significant increase in the share of electricity production. In addition, established policy gives priority to RES production in the daily dispatching schedule over electricity produced through conventional burning of fuel.

The result of these policies – especially the latter - leads to a re-evaluation of the value of stored capacity in power companies. Since RES electricity enters the system first and since a lot of electricity is produced through RES, the times at which electricity is produced from redundant traditional capacity are fewer. That is, the possibility of exercising the real option is now lower and the reaping of convenience yields is less frequent. This development may have resulted in losses for the European conventional power companies.[2] This further suggests that the power energy sector in Europe will likely face restructuring that could affect European energy security.

II. STYLIZED FACTS OF EUROPEAN ELECTRICITY MARKETS AND COMPANIES

Companies

The 14 major generating European companies in our sample dominate the European electricity market, as they account for almost 50% of the EU28's electricity generation (Figure 1). They are also major players in a global context. Most of them are incumbent companies that enjoy high market shares in the electricity market but also utilize a well-diversified portfolio of production technologies.

There are major differences between the utilities analyzed in this study in terms of fuel mix used for electricity production (Figure 1).[3] For all except for EDF, solid and fossil fuels clearly dominate the production mix, accounting for 95% of generation in some cases. For most of these companies coal is the dominating fuel (RWE DE, ENEL, E.ON DE, ENDESA, ENBW, E.ON UK, RWE npower), in others natural gas (IBERDROLA, Edipower, EDISON). Nine out of the fourteen companies have nuclear production, which accounts for 20% to 58%

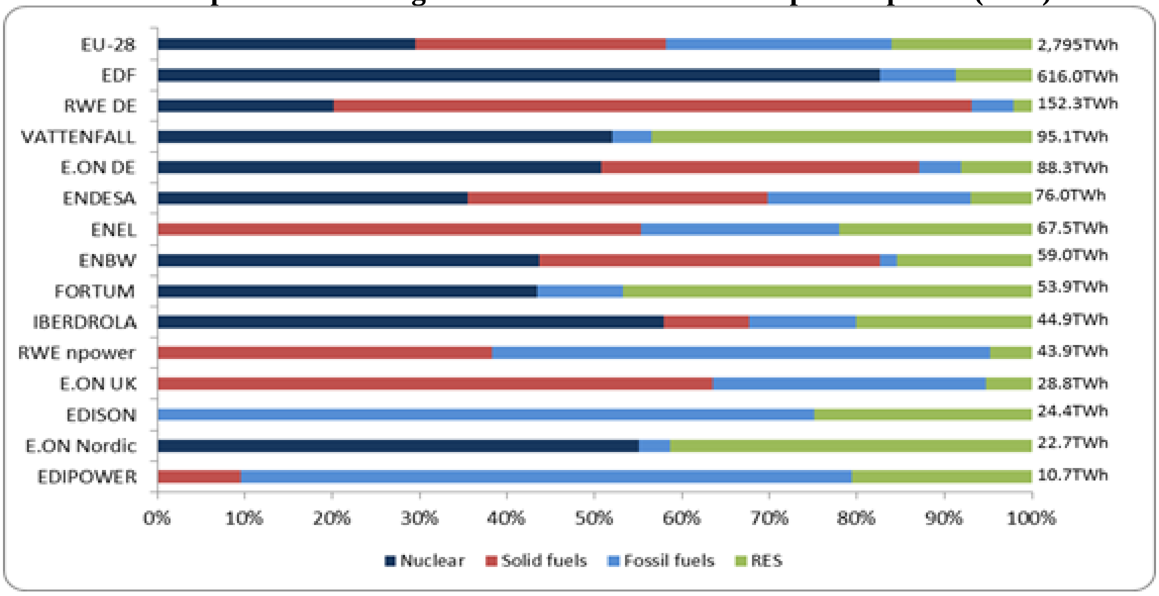
[2] See "Europe's electricity providers face an existential threat," *The Economist*, October 12th, 2013.

[3] Data retrieved form annual reports are not published in a common manner and for some companies the figures concern estimations based on the best available information.

of production except EDF. EDF, by far the EU's largest electricity producer, produced around 87% of its electricity from nuclear in 2012. The share of renewable energies ranges from 2% in the case of RWE DE to around 45% in the case of Vattenfall and Fortum. The vast majority of electricity production from renewable energies concerns hydro. The latter companies, as well as E.ON Nordic present similar generation fuel mixes.

Figure 1

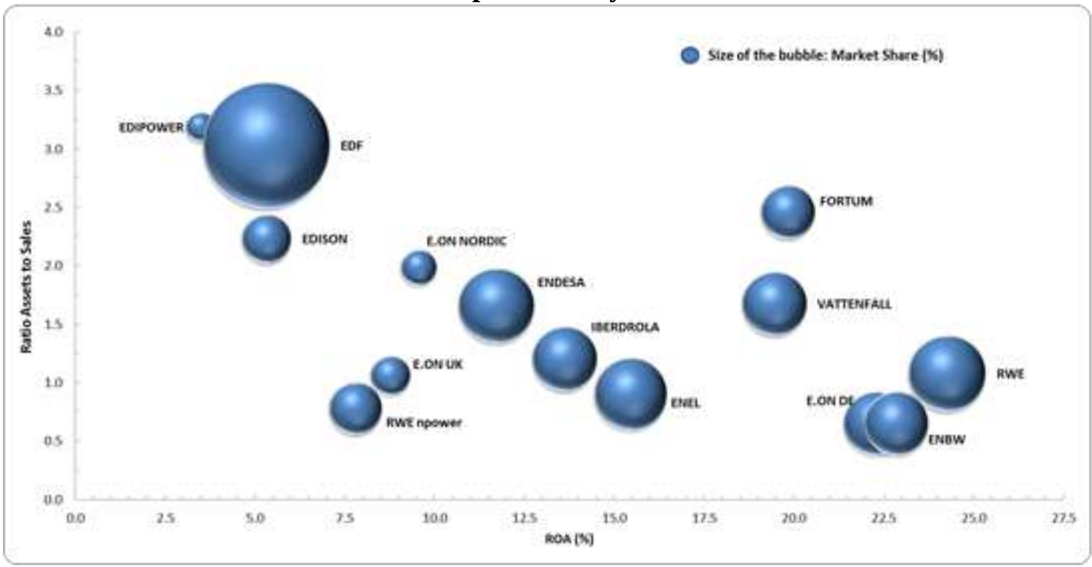
Power production and generation fuel mix of the sample companies (2012)



Source: Company annual reports

Similarly to the generation fuel mixes, one may observe the significant heterogeneity in terms of profitability among the companies included in the sample (Figure 2). It varied from 3.5% for Edipower to 24.2% for RWE, on average, over the period 2004-2011. Introducing the 33rd and 66th percentile of the sample, the companies can be classified into three groups regarding the level of profitability: low, moderate and high. The first group includes Edipower (3.5%), EDF (5.3%), Edison (5.3%) and RWE npower (7.8%), the second includes E.ON Nordic (8.8%) and E.ON UK (8.8%), Endesa (9.5%), Iberdrola (11.7%) and ENEL (13.6%) and the third includes Vattenfall (15.4%), Fortum (19.4%), E.ON DE (19.8%), ENBW (22.3%) and RWE (22.8%). Consequently, comparisons among companies will have to take into account this great heterogeneity in profitability, along with their market share and portfolio characteristics.

Figure 2
Comparison of companies in terms of market share, ratio assets to sales and profitability



Source: Company annual reports

Figure 2 shows that the profitability of companies is driven more by the characteristics of their portfolio, rather than the level of the competition in the market. In most cases, and especially for companies that belong to the third group, the higher levels of profitability are accompanied with lower levels of the ratio assets to sales. This indicates that companies with larger share of plants that require lower capital investments, usually peak and intermediate plants, are expected to have higher earnings per unit of assets. However, to a lesser extent, there are some cases where higher market shares appear to have higher impact on the profitability, such as in case of Fortum and Vatttenfall.

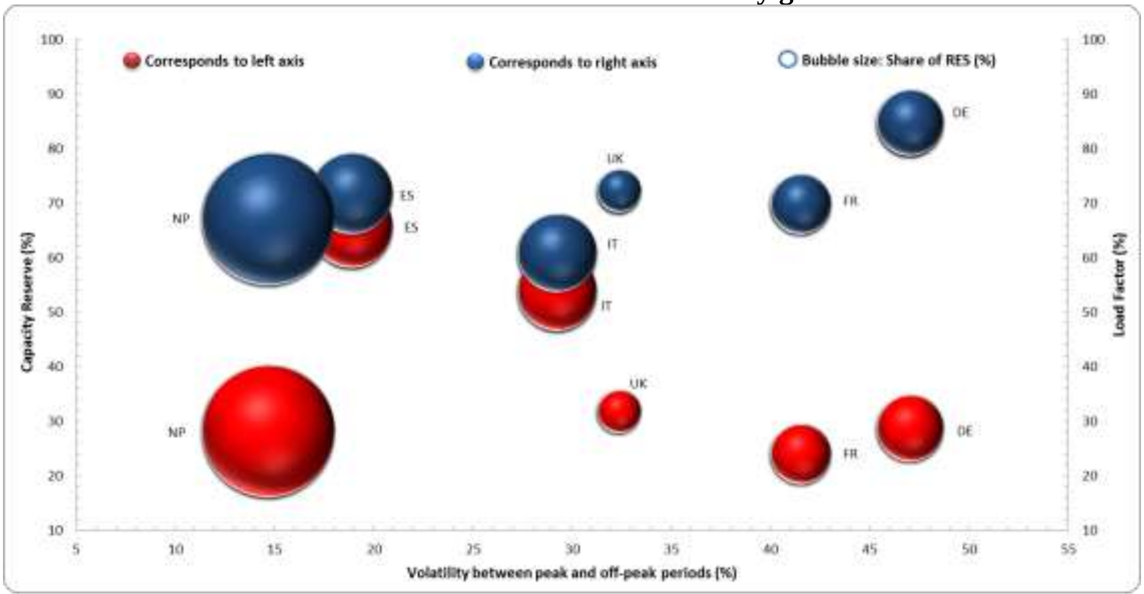
Countries

In addition to company specific characteristics, it seems that the profitability of companies may also be affected by the conditions prevailing on each national market. Various variables that represent the specificities of each country's market (volatility of prices, capacity margin, load factor, share of Renewables) exhibit great heterogeneity (Figure 3).[4] In general higher shares of Renewables tend to be associated with lower levels of variability of prices between peak and off-peak periods, as the deployment of Renewables affects the merit order and especially the peak plants operations. As a consequence, the price dispersion between these

[4] While they will be descibed in more detailed later, a short definition of these variables is in order: *capacity margin* is the excess of total installed capacity over peak demand; *load factor* is the average load divided by the peak load.

two periods of electricity consumption is lower. This is more obvious in the case of the Nordic market, known as Nord Pool. However, in some countries the yearly load profile, represented by the load factor and the capacity margin of non-volatile generation technologies appears to be influencing market conditions. In general, higher load factor levels and lower capacity margin levels appear to lead to greater variability of the market. Nevertheless, the above variable effects on profitability are mere indications and conclusions will be drawn after rigorous statistical tests are performed in Section VI.

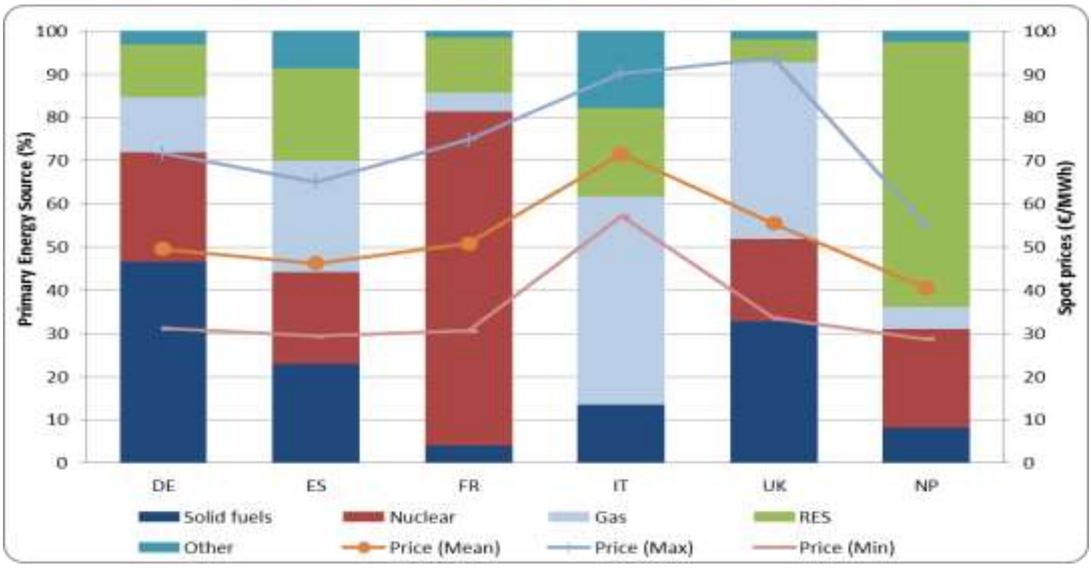
Figure 3
Comparison of European markets in terms of volatility, capacity reserve, load factor and share of Renewables over total electricity generation



Source: Reuters, National Reports and own estimations

Figure 4 shows that the electricity fuel mixes clearly differ among the markets included in the sample. Spain has one of the most diversified electricity fuel mixes, while France and Nordic countries seem to be less dependent on external factors disruptions, as imported energy fuels account for a small percentage relative to other markets. The dominant energy source in the electricity fuel mix of Italy and UK is natural gas; in France is nuclear power, in Germany is coal and in Nordic countries is RES production. This fact affects significantly the marginal spot prices, consequently the volatility of their prices too. Markets that rely on nuclear, RES and to lesser extend to solid fuels tend to exhibit lower spot prices compare to those markets that rely on natural gas plants.

Figure 4
Breakdown of electricity fuel mix by source and country (%) and spot prices



Source: Reuters, Eurostat, Nordel

In conclusion, it is important to note that the profitability is interrelated with the flexibility of the plants included in companies' power portfolio and the frequency of periods of shortage. Given this, the aforementioned indicators imply in a general way that participants in the German market are likely to have higher earnings, followed by companies operating in the Nordic market and, to a lesser extent, by participants in the Spanish market. In other countries such France, Italy and UK, the profitability is affected by the size of assets which concerns mainly base-load plants. Especially in France, the profits of the state-owned company EDF are influenced by the regulatory decisions,[5] as well.

III. METHODOLOGY

With the aim of understanding the determinants of power producers' profitability, and especially whether returns capture a convenience yield to 'stored' production capacity, the analysis concerns time series data on ROA of 14 European electricity generation companies.

We posit that performance is driven by two distinct functions. The first one relates profitability to different variables (market share, size of firm, operating efficiency) based on the received 'structure performance hypothesis,' as extended by the use of a Cournot-type model (Schmalensee (1987)). In addition, profitability in this function can be affected by market related variables that capture time effects of energy and climate policies. The second function driving performance is related to the possible existence of a real option, whereby

[5] In 2010 France introduced a law known as NOME act which, among other things, gives access to EDF's rivals on nuclear generation based on a regulated tariff established each year at the beginning of its enforcement by the government and after 2014 by the energy regulator.

stored capacity enables the capture of convenience yield. If indeed ROA includes such a convenience yield, it is expected to be positively related with the volatility of spot prices. Furthermore, the value of the real option will be expected to decline as excess capacity increases.

In the existing literature the best and most widely used indicator of profitability is ROA, based on earnings before interest and taxes. This avoids influences due to different capital structures and taxation policies (Schmalensee (1987)). This indicator measures the relationship of earnings to total assets and it reflects the ability of companies to utilize their assets to generate profits. According to theory, the profitability of companies is determined by internal and external factors (Khrawish (2011)). Internal factors concern company-specific determinants while external factors concern market related determinants of profitability. The empirical model takes the following form:

$$ROA_{ijt} = c + \sum_{n=1}^{n} b_n X_{ijt}^{n} + e_{ijt} \quad (1)$$

$$e_{ijt} = k_{ij} + v_t + u_{ijt}$$

Where ROA is the return on assets and represents the profitability of the company *i*, operating in country *j*, at time *t*, with *i*=1,….,D, *j*=1,2…J, t=1,2,…,T, *c* is the constant term, *X* is a vector of *n* explanatory variables and e is the residual with k_{ij} and v_t the unobserved company-specific and time-specific effects, respectively, and u_{ijt} the idiosyncratic error.

Specifically, in this study, two variables are used as internal determinants of performance: market share (MRK_SHARE) and the ratio of assets to sales (EFF) that provides a measure of operating efficiency.

It is widely recognized that one of the main determinants of business profitability is *market share*. According to the traditional structure-conduct performance (SCP) hypothesis, increased market share enables the capture of monopoly rents. Under most circumstances, companies that have achieved a large share of their market are indeed more profitable than their rivals with smaller market shares. However, we must note that in the electricity market, market share is also closely linked to the diversity of the producers' portfolio of plants. The power portfolio might consist of a combination of base-load, intermediate and peak plants or might include only one of these types of plants. Base-load plants are characterized by high capital cost and lower variable cost, have a high capacity factor (more than 70%) and are considered as an inflexible production base due to their technical constraints. Conversely, peak plants have a high variable cost and lower capital cost, operate fewer hours per year (<30%) and play a crucial role in the flexibility of the system by ensuring supply in peak demand periods.

Base-load plants include nuclear, hydro, coal and geothermal units; peak plants include open-cycle gas plants whereas intermediate plants refer to coal or natural gas combined cycle plants. Taking into account the above techno-economic characteristics, within a specific electricity market, the ***ratio of assets to sales*** (EFF) is included in the analysis to capture two features: First, the impact of the power portfolio structure on returns, as a higher ratio indicates that assets are more weighed towards base-load plants; and secondly to measure company's efficiency in generating revenues from its assets usage.

In order to ensure that besides the current information set, other individual effects are taken into account in the analysis, a fixed-effect specification has been chosen. It is well known that the omission of these characteristics can bias the ordinary least squares coefficient estimates. These effects reflect the unobservable time variant and invariant companies' differences, either per company or per a specific group of companies, or countries.

In addition to the company-specific variables described above, the analysis includes three variables as external factors of profitability: spot price volatility (σ), the share of Renewables over the total electricity production (SH_RES), the capacity margin (CAP_MARGIN), and the load factor of the energy system (LF).

Spot price volatility is calculated as the standard deviation of the difference of the average prices between peak and off-peak demand periods. Following Kalantzis and Milonas (2010), peak demand periods were defined as the hours between 8:00-20:00, while the remaining hours are defined as off-peak periods. In this spirit, the annualized volatility σ_{ijt} for year t (Zareipour, Bhattacharya and Canizares (2007)) is the standard deviation of the change in price P(ijd) for the *i*th firm, the *j*th country on the *d*th day over day d-1 and is equal to:

$$\sigma_{ijt} = \sqrt{\frac{\sum_{d=1}^{D} (r_{ijd} - \bar{r}_{ijd})}{D-1}}, \text{ where } r_{ijd} = \ln\left(\frac{P_{ijd}}{P_{ijd-1}}\right)$$

As in other studies for storable commodities (i.e., Milonas and Thomadakis (1997a)), it is expected that the higher the volatility, the higher the profitability of the firms as they will be able to utilize more often their plants and exercise more often the real option that is equivalent to the convenience yield embodied in 'stored' capacity.

Renewables penetration (SH_RES) is one of the main factors that are expected to exercise a negative effect on the return of investments in conventional power plants, especially those that concern peak and intermediate plants, as discussed above. In fact the policy preference for renewable participation in total generation may affect negatively both the monopoly rents captured by conventional producers and the convenience yields captured by their excess capacity. As a result, we enter this variable into the model in order to capture its potential impact on company profitability.

An important variable possibly connected to convenience yields is ***capacity margin*** (CAP_MARGIN). This is defined as the excess of total installed capacity over peak demand and for the purpose of this study it is calculated as the ratio of total installed capacity, *excluding wind, geothermal and solar electricity capacity* within a country, to maximum demand within a year. In general, this variable is used to identify the ability of generation to match demand at all times. In the long run, this is ensured through investments in generation and other infrastructure, which will enable the power system to cover peak demand. In the short run, security of energy supply is guaranteed by the availability of flexible capacity (peak plants) to cover for demand fluctuations, loss of generation units due to unplanned outages as well as variability of RES production. When the level of capacity margin is considered low (usually below 20%), it may result in unnecessarily high prices to pay for the lack of capacity and as well result in supply issues if its level is not sufficient to cope with demand. Conversely, when it is too high, it could, in general, result in lower prices as the most expensive power plants in terms of variable costs, usually peak plants, will not participate in the dispatching schedule due to the merit order effect. Thus, capacity margin is generally expected to relate negatively to convenience yield in this market.

Finally, the ***load factor*** (LF) has been taken into account in the analysis as a proxy for demand conditions over a year. This indicator is defined as the average load divided by the peak load. Its value is always less than one. A high load factor means power usage is relatively stable. Low load factor shows that a high demand appears with some frequency. To service such demand peaks, capacity may sit idle for long periods, imposing higher costs on the system and requiring compensation via a convenience yield.

Having accounted for the above factors, to test the basic hypothesis, a fixed effect panel data model was employed.

Specializing equation (1) to reflect the variables described above, two models are formulated as follows:

$$ROA_{it} = c + b_1 MRKT\_SHARE_{it} + b_2 \sigma_{it} + b_3 EFF_{it} + b_4 CAP\_MARGIN_{it} + b_5 LF_{it} + e_{it} \quad (2)$$

$$ROA_{it} = c + b_1 MRKT\_SHARE_{it} + b_2 \sigma_{it} + b_3 EFF_{it} + b_4 SH\_RES_{it} + b_5 LF_{it} + e_{it} \quad (3)$$

We use the two alternative specifications to check the impact of conventional capacity margin in (2) while the impact of renewable shares in total capacity in (3).

It is expected that the coefficients of company market share, spot price volatility and load factor will be positive, while the coefficients of the share of Renewables, capacity margin and the ratio of assets to sales will be negative for reasons explained above.

The possible significance of spot price volatility and capacity margin will offer strong indication that total performance as measured by ROA includes convenience yields accruing to 'stored' capacity.

IV. DATA AND DESCRIPTIVE STATISTICS

The data consist of an unbalanced panel of 14 electricity companies that operate mainly in six of the most mature electricity markets in Europe. The sample period includes eight years and starts in 2004, the year when the International Financial Reporting Standards (IFRS) were introduced, and ends at 2011. The data for the economic and market structure variables were retrieved from annual reports of selected companies, as available. The companies and the years included in the sample are determined by data availability, especially on return on assets (ROA), market shares (MRKT_SHARE), generating assets and sales retrieved from annual reports by market and business activity. In addition, the criterion to include in the analysis only companies with significant market shares from several EU countries and with varying power generation portfolios determined the sample: E.ON, RWE, ENBW (Germany), EDF (France), RWE nuclear, E.ON UK (UK), EDIPOWER, EDISON, ENEL (Italy), ENDESA, IBERDROLA (Spain), E.ON, FORTUM, VATTENFALL (Scandinavian countries).[6]

Energy market variables, such as the share of Renewables (Hydro, wind, solar, biomass, geothermal) in total electricity production (SH_RES), the exchange rate for converting the financial data into euros and the necessary variables (installed capacity per technology and peak demand) for calculating the capacity margin (CAP_MARGIN), were collected from various databases and sources such as EUROSTAT, the Energy Information Administration (EIA), the European Network of Transmission System Operators for Electricity (ENTSO-E) and the Council of European Energy Regulators (CEER). Finally, the data for the hourly electricity spot prices during weekdays, which is used for calculating the average spot price and volatility of prices between peak and off-peak hours (σ) were collected from Reuters database for the selected electricity markets: France (POWERNEXT), Germany (EEX), Italy

[6] Note that different sources of information (annual reports, press releases, web sites, national reports) were combined to construct a comparable dataset, as sometimes the available information given by companies was contradictory, especially regarding sales and electricity production per country and business segment.

(IPEX), Spain (OMEL), UK (APX UK) and Scandinavia (Nord Pool). The electricity spot prices are denominated in euros (€) per megawatt hours (MWh).

Table 2
Descriptive statistics of regression variables

	ROA	SH_RES	MRKT_ SHARE	EFF	σ	CAP_ MARGIN	LF
Mean	13.70	26.67	24.45	1.60	29.75	39.66	71.25
Max	37.83	65.80	90.20	4.20	107.54	73.26	87.29
Min	2.88	4.41	0.00	0.00	6.54	15.28	58.84
Std. Dev.	7.72	19.91	19.86	0.90	20.40	16.54	8.85
COV	0.56	0.75	0.81	0.56	0.69	0.42	0.12
Skew.	0.63	1.04	2.27	0.60	1.83	0.68	0.41
Kurt.	2.70	2.58	7.95	2.50	7.02	2.11	1.91
J-B	7.48	21.19	204.86	7.45	137.78	12.24	8.59
Prob.	0.02	0.00	0.00	0.02	0.00	0.00	0.01
Obs	107	112	109	107	112	110	110

Table 2 presents descriptive statistics of both the dependent and independent variables for the panel data analysis. In general, all the variables exhibit high variation. Surprisingly, market share exhibited the highest coefficient of variation (COV), followed by the share of Renewables and spot price volatility. The level of COV of the rest of variables was around 0.5, while that of spot prices was the lowest. This indicates that there is differentiation among the companies in all variables. The Jarque-Bera statistics imply that data series are not normally distributed and thus the null hypothesis of normality cannot be accepted.

Table 3
Correlation analysis of regression variables

	ROA	SH_RES	MRKT_ SHARE	EFF	σ	CAP_ MARGIN	LF
ROA	100%						
SH_RES	22%	100%					
MRKT_SHARE	-10%	-26%	100%				
EFF	-52%	26%	27%	100%			
σ	17%	-48%	17%	-17%	100%		
CAP_MARGIN	-22%	-9%	-16%	-8%	-24%	100%	
LF	52%	-34%	8%	-48%	40%	-31%	100%

Table 3 presents the results of the correlation analysis of the variables to identify the level of association among them and to detect possible multicolinearities (Baltagi (2001)). As expected of the highest levels of correlation is observed between spot price volatility and the share of Renewables and the load factor with the ratio of assets to sales and with price volatility. Renewables penetration plausibly affects spot prices as it influences residual demand for electricity and thereby spot price volatility. The ratio of assets to sales (EFF) is also plausibly affected by capacity margin through the spot price channel. However, none of the correlation coefficients among the independent variables suggest severe multicolinearity, as all of them are below the 0.5 threshold (Gujarati (2003)).

V. EMPIRICAL RESULTS

In this section, the results of the empirical estimation of equations (2) and (3) are presented. The cross-section and period variation was examined based on the likelihood ratio and Hausman tests for fixed and random effects,[7] respectively, in order to control for firm heterogeneity and reduce collinearity among the variables (Arellano and Bover (1990)). Both tests suggest that a fixed effect specification is more appropriate than the random effects model. Given this, a cross-section and time fixed effect model was employed as determined by the highly statistical significance of the joint-hypothesis.[8] All standard errors and t-statistics are computed using White's heteroskedasticity correction factor that yields robust error terms. Greene (2000)[9] suggests White's heteroskedasticity-consistent standard errors as an appropriate method for dealing with potential biases in t-statistics that are inherent with the use of panel data.[10]

The estimated coefficients for the two alternative specifications of the model are contained in Table 4.1 and 4.2. The goodness of fit is very satisfactory, judging by the fact that almost all independent variables are statistically significant at a high significance level (5% or better). Independent variables all obtain the expected sign.

Table 4.1
Regression estimates

Variable	Coefficient	
	Equation (2)	**Equation (3)**
C	1.759***	3.806***
LOG(MRKT_SHARE)	0.331**	0.245*
LOG(EFF)	-0.336***	-0.310***
LOG(σ)	0.083**	0.092**
LOG(CAP_MARGIN)	-0.306**	-
LOG(SH_RES)	-	-0.523***
LOG(LF)	2.252**	2.047***
R^2	**0.924**	**0.927**

Note: *, **, *** indicate significance at 10%, 5% and 1% confidence level, respectively

[7] Due to space limitations, results are available upon request.
[8] This technique eliminates the potential biases in the resulting estimates due to correlation between unobservable individual effects and the explanatory variables included in the study.
[9] See page 579.
[10] The White cross-section specification was chosen for equation (2), which allows for a different residual variance for each cross section and the white period specification for equation (3), which assumes that the errors for a cross-section are heteroskedastic and serially correlated (cross-section clustered).

Table 4.2
Regression estimates

Variable	Coefficient	
	Equation (2)	**Equation (3)**
Cross-section effects		
EDF	0.613***	2.625***
RWE npower	1.056***	2.538*
E.ON UK	1.362***	2.818***
ENBW	1.573***	3.579***
E.ON DE	1.610***	3.614***
EDISON	1.683***	3.541***
EDIPOWER	1.711***	3.473
RWE DE	1.714***	3.740***
ENDESA	1.841***	3.782***
IBERDROLA	1.970***	3.894***
E.ON NORDIC	2.149***	4.755***
ENEL	2.190***	4.142***
VATTENFALL	2.355***	5.046***
FORTUM	2.619***	5.269***
Fixed period effects		
2004	1.706***	3.694***
2005	1.692***	3.666***
2006	1.692***	3.687***
2007	1.779***	3.818***
2008	1.725***	3.764***
2009	1.824***	3.898***
2010	1.863***	4.036***
2011	1.843***	3.995***
R^2	**0.924**	**0.927**

Note: *, **, *** indicate significance at 10%, 5% and 1% confidence level, respectively

The results shown in Table 4.1 and 4.2 are generally confirmatory of the basic hypothesis and of the stylized facts observed in section III.

We first comment on the fixed effects as shown in Table 4.2 Companies with higher ROA presented a higher constant term in both equations. This confirms the significant variation in returns across companies that we note din descriptive statistics. Over the years the constant term remained approximately stable until 2008; after a small decline in 2009, it resumed an increasing trend. This pattern appears to track the evolution of crude oil prices over the period 2004-2011.

Turning now to the main estimation results in Table 4.1 we note a general confirmation of the hypotheses which were formulated. Firstly we note that the existence of a strong component of convenience yield within general profitability of power producers in Europe is strongly confirmed by the statistical performance of the two variables which were hypothesized to capture it: spot price volatility which exhibits a strong positive influence on actual returns; and the overall capacity margin (excluding capacity of Renewables) which exerts a significant negative influence, as expected. These findings imply that even in a technologically complex environment, such as the electricity generation market, a strong real option is embedded in conventional capacity decisions. Thus, the theoretical conjecture that even in the absence of storable inventories, the logic of 'convenience yield' is carried over to 'stored capacity' is validated by these results.

Parallel to the findings about convenience yield, the performance of the other variables confirms hypothesized effects. The role of market share is consistently positive, suggesting the influence of monopoly rents, which naturally accrue to firms with technology portfolios and mixtures of base and peak plants. Secondly, the effect of the ratio of assets to sales is also predictably negative, as theory would suggest, irrespective of the technological mix. The positive impact of the load factor variable signifies that, once the convenience yield aspect of the returns is controlled for, a market with more stable demand characteristics leads to higher returns, ceteris paribus.

Turning now to equation (3) and the role of the variable measuring the share of generation from renewable sources (SH_RES), it is observed that the signs of the remaining variables do not change, relative to equation (2) estimates. The (SH_RES) variable obtains a significant negative coefficient. Thus, very clearly, the increase in the share of generation from renewable sources exercises a negative effect on returns to companies undertaking conventional generation. Although not unexpected, this relation has implications both for market structure and for the political economy of electricity generation in Europe.

In order to promote the use of energy from RES within the European Union and attain reduced carbon emissions, many European countries have established subsidies for investment outlays and/or the price paid for each kWh produced from RES. As a result, RES technologies have gained a significant increase in the share of electricity production in national markets. Furthermore, according to established policies, RES production is given priority in the daily dispatching schedule over electricity produced through conventional burning of fuel. This implies that RES generating companies are not only given incentives for attaining a larger share of the market but are also relatively better shielded from the uncertainty of demand in day-to-day operation.

The result of these policies leads to a re-evaluation of the value of stored capacity in power companies. Since RES electricity enters the system first and since a significant portion of electricity is produced through RES, redundant capacity from conventional producers increases. This would imply, ceteris paribus, that convenience yields captured by 'stored capacity' decline. On the other hand, new forms of uncertainty arise for conventional producers who will have to respond to fluctuations in RES supplies which arise from external factors (weather, wind etc.) Thus, the existence of convenience yields is still warranted, and *this is plausibly validated by the strong positive coefficient of the volatility factor* in regression (3). The fact that volatility still plays a very significant role in the ROA of power generation companies is a clear indication that convenience yields accruing to excess capacity remain valid even after the intervention of RES generation. This in turn suggests that although general monopoly rents of conventional producers may decline as RES shares increase, convenience yields are still available to be captured by 'stored' capacity even in the new environment.

VI. CONCLUDING REMARKS ON EUROPEAN POLICY

The policy of subsidization of renewable power generation in Europe has a series of effects that must be separately evaluated. First, its effect on the reduction of emissions is a primary policy goal, but it is outside the scope of this paper to comment on that. Secondly, it implies a revaluation of investments in conventional generation capacity with possible negative effects since the earlier ability of conventional producers to obtain monopoly rents is reduced. This will clearly affect the incentives for investment in conventional generation in the future, and policy must take this possible impact into consideration if generation is to evolve smoothly and within a context of sufficient supplies and energy security.

Thirdly, there is the issue of priority of supply. Current policies give priority to renewable sources, thus securing for them not only a significant slice but also a more stable portion of total demand. In other words, preferential policies do not only allocate production in favor of renewable generation but also allocate risks. This implies that conventional generators must service a relatively more uncertain portion, ceteris paribus, thereby requiring higher returns from their investments. A portion of these higher returns may in fact be reaped in the form of convenience yields which appear to continue to be present in national electricity markets despite the gradual and significant growth of RES generation.

A broader issue affecting policy and policy risks lies in the finding which surfaced both in our general statistics and in our estimation of fixed effects: heterogeneity in production technologies, demand characteristics, fuel mixes and capacity margins is very evident among generating companies. We also know that national markets vary both in regulations and in the makeup of the population of users (industry, households, transport etc). Thus, it is really far-fetched to think of a unified European market for electricity, despite the fact that all the companies in our sample compete in the European market for capital, which enjoys a higher degree of integration. This implies that a common policy may have different results and may face the risk of creating different unintended consequences in so fragmented an environment. Cautiousness and careful evaluation of responses to policy measures are warranted in such a case.

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