Incorporating Carbon Risks into Company Valuation

The Case of the European Utility Sector

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FOREWORD

Financial markets over the last years have demonstrated some fundamental failures to identify, assess and ultimately manage a wide range of risks. Government and policy makers have also fallen short in applying necessary market regulation.

The growing global environmental and social challenges are posing future risks of dramatic magnitude and consequence. These risks are of material significance for financial markets, especially in a resource constrained world. When we consider what it will take to decarbonize societies in order to keep climate change within manageable boundaries these aspects will have to become much more central to what financial markets needs to address systematically.

To date, capital markets and financial institutions have not demonstrated that they comprehensively assess climate change or its associated impacts, or integrated it into strategic business processes. There are many reasons for this which range from a persistent gap in comprehensive and comparable data, to uncertainty over cause and effect, and the missed reflection of today's relevance of longer timescales of climate change impacts.

WWF Germany supported the development of this report in order to better understand the options of integrating the aspects of climate change related risks into the risk premiums when calculating the cost of capital for companies. Can capital market based theory be extended and serve as a starting point? In how far are current capital markets already reflecting carbon related risks and how can tools be formulated to help progressing the debate amongst the financial sector actors?

It is promising to see that already some carbon risk premiums can be identified in stock price levels, even on the basis of imperfect markets as the EU emissions trading market in its early days demonstrated. This report focuses on the electric utilities' sector and it will be important to develop similar approaches to address climate change implications across all industries. Companies need to be confronted with adequate risk premium levels by capital markets to be incentivized to develop an appropriate decarburization strategy. Likewise, regulators and policy makers need to understand and implement regulation that is above all credible and sends the right signals to both, capital markets as well as industries.

WWF sees this report as a further step in working together with financial markets on a systematic and comprehensive integration of the consequences arising from climate change - the need to decarbonize our economies and the consequences from unfolding climate change. However, the responsibility lies with the finance sector to urgently improve institutional responses to climate risk management and, as addressed in this report, valuation practices.

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Introduction

Motivation

To meet its obligations to reduce greenhouse gas (GHG) concentrations under the Kyoto Protocol, the European Union (EU) established a cap-and-trade system for carbon dioxide emissions. Implemented in 2005, the EU's Emissions Trading System (EU ETS) led to liquid, transparent markets for emission allowances and the incorporation of allowance prices into business decisions of companies. As more than half of total emissions refer to the energy industry[1], especially utilities are faced with direct and indirect carbon risks[2], which mainly materialize as price risks of the necessary carbon emission allowances. Consequently, utilities face the challenge to adapt their business strategies in order to optimize future carbon price risk of their generation portfolios.

Against this background, theory and business are confronted with the task to assess corporate value at risk from constraining carbon emissions and to incorporate carbon risks into company valuation. Our study demonstrates the immediate necessity to extend the scope of conventional valuation methods for carbon to comprehensively reflect companies' value risk exposure.

[1] In the following we use energy and utility industry as synonyms.
[2] In the following we use carbon and CO_2 risk as synonyms.

Carbon Risk in Valuation Practice

On the investor side, investment professionals are already looking for approaches to incorporate CO_2 risks in valuing utilities in particular. However, there exists no standard approach to integrate these carbon risks into corporate valuation[3].

According to the Carbon Disclosure Project investor's current methods are limited to computing ratios in order to analyze competitors in terms of emission levels.[4] In contrast, recently Carbon Trust and McKinsey[5] have adjusted company cash flows to take emission regulation into account before conducting a Discounted Cash Flow (DCF) company valuation. The core of this analysis is the idea that CO_2 emissions are value drivers with a direct impact on the cash flow.

Summing up, existing studies rather adjust cash flows of a firm as discount rates to take carbon risk into account. The interactions between capital markets in terms of stock returns and price returns of emission certificates are still neglected.

Capital Market Approach

To fill this gap our study introduces a valuation methodology based on capital market theory. From our point of view, the incorporation of carbon risks into corporate valuation should be implemented by adjusting the cost of capital. We suppose capital markets identify carbon as systematic risk factor and develop an approach to adjust equity costs of capital for company specific carbon risk.

Using a capital market approach, we do not just investigate cash flows with regard to CO_2 emissions and prices. In fact, we incorporate CO_2 risks by adjusting the appropriate discount rate. The advantage of our valuation proposal is obvious: While an adjustment of the carbon cost via the cash flow is rather subjective, on the contrary, a capital market approach is based on objective criteria.

[3] Please, refer to the appendix for a more detailed presentation of existing valuation approaches.
[4] See Carbon Disclosure Project (2008): Carbon Disclosure Project Global 500 Report 2008, www.cdproject.net.
[5] See Carbon Trust / McKinsey (2008): Climate Change: A Business Revolution?, London 2008.

In our study, which compromises three European utilities, we demonstrate that the use of a capital market model in the valuation process is a practicable and so far unused option to take carbon risks into account. Our approach presents an extension of the wide used CAPM and can easily be integrated in a traditional DCF valuation process, which is broadly accepted by academics and practitioners for company valuation.

As the methodology aligns on an extension of common valuation techniques, our study should enable financial analyst to review their valuation models with regard to essential extensions to cope with carbon risks. In addition, as capital market data required for the value at risk analysis is publicly available, the effort to conduct the valuation is low.

We show that a high carbon risk corresponds with an additional risk premium, which raises equity costs causing a lower equity value. We advice to take these interactions between capital markets in terms of stock returns and price returns of emission certificates into account. While investors should add the carbon risk of a utility to their required risk premium, utilities need to know their carbon exposure in order to define future investment strategies.

Conventional valuation models are not able to cope with these assessed costs related to carbon risks. Hence, it is by all means worthwhile to enhance existing valuation techniques. The merit of an extended valuation methodology based on a capital market perspective is to identify and assess value at risk from carbon and not being theoretically correct.

Before we present our model and the methodology, we outline the regulatory environment and characteristics of the European utility sector, which motivate us to analyze this sector in the context of carbon risk.

The Energy Industry

Our sample covers three European utilities, RWE, Iberdrola and CEZ operating mainly in their domestic power markets, Germany, Spain and the Czech Republic, respectively. The utilities taken into account are facing similar risks. First, in all countries competitive reforms are adopted in order to create a single European electricity market.[6] Second, the European power plant park is rather old making replacement investments necessary in the near future. Third, European climate policy and the introduction of the European Trading Scheme (ETS) challenge the business strategy of the utilities with respect to optimization their future generation mix. However, differences do exist concerning the regulation of the individual country. Therefore this section highlights major challenges for the utility industry and explains national characteristics of the power markets.

National Distinctions of Power Markets

In Germany the majority of generation capacity refers to RWE, E.ON, Vattenfall and EnBW with market shares of 30, 21, 12 and 12 percent, respectively.[7] Despite a high concentration of the generation market, the German wholesale power market is well established and highly liquid. This is due to its geographic location in Central Europe allowing cross-border trade flows with Germany's neighbor states.[8] Very similar to Germany, the three largest utility firm's in Spain, Endesa, Union Fenosa and Iberdrola collectively own more than 80 per cent of the generation capacity. Before the credit crunch, the Spanish wholesale power market was characterized by a strong growth of demand reaching more than twice the European average growth rate. Moreover, the launch of a single Iberian market allows Spanish and Portuguese generators to sell their electricity either in Spain or Portugal, which will boost the development of the power market. In addition, interconnections do exist with France and Morocco. Germany and Spain are competitive and liberalized markets, as there is no single utility firm controlling a large amount of the power generation. Moreover the business entities generation and network activities are separated by law. Therefore utilities are able to compete in generation, as the access to the grid is guaranteed.[9]

In contrast to the German and Spanish market, the Czech power market is rather non-competitive. Roughly speaking, around two thirds of the generation capacity is owned by CEZ. Consequently, the number of Czech generation suppliers is limited in comparison to other European power markets. However, the number of new market entrants has been increasing recently. The potential for the Czech power market is mainly driven by its physical location. Furthermore, the regulatory environment attracts investors to participate in the power generation market. The interconnections with Germany and Scandinavia support the further development of the Czech wholesale power market.[10]

Liberalization and Fuel Mix

In the beginning of 1990 England and Norway opened their electricity markets for competition. The first European Directive aiming to create a single electricity market was adapted in 1996.[11] Before the liberalization of electricity markets in 1998, utility companies used to pass on their costs and cost changes to customers. In comparison to competitive electricity markets, the former monopolistic market structure used to guarantee stable prices, which were related to the costs of a utility company. Nowadays, utility companies are exposed to financial risks as markets are open for competition. With the deregulation of electricity markets power exchanges for trading purpose have been established. Prices are now based on market principles and not set by a

[6] Liberalisation of the energy markets refer to the European Directive of 1996.
[7] See Knight, E. (2008), The Economic Geography of Carbon Market Trading: How legal regimes and environmental performance influence share performance under a carbon market, Working Paper, Oxford University Centre for the Environment.
[8] Austria, Czech Republic, Denmark, France, Luxembourg, Netherlands, Poland, Sweden and Switzerland.
[9] See Knight, E. (2008), The Economic Geography of Carbon Market Trading: How legal regimes and environmental performance influence share performance under a carbon market, Working Paper, Oxford University Centre for the Environment.
[10] Datamonitor (2005): Future Development of European Wholesale Energy Markets.
[11] See Green, R. (2006): Investment and generation capacity, in Competitive Electricity Markets and Sustainability, Lévêque, F. (ed.).

regulatory authority. In particular, new market entrants have to take the uncertainty of fluctuating electricity prices into account.[12]

New market entrants mainly rely on gas-based generating capacity as this technology is more flexible and characterized by a shorter payback period compared to coal power plants. The number of gas-based power generation systems has increased massively in Europe. Moreover cash flows of gas power plants can hedge themselves, as electricity is correlated to gas and carbon markets.[13] However, the increase of cross border trade and the access to larger growing markets also reduces the risk of large scale investments.[14] The Spanish energy policy favors renewable energies, which has limited the new gas capacity in comparison to other European countries. This is one example for countries, which promote a national fuel mix by subsidizing prices (i.e. renewable, lignite).[15]

Summing up, the European Union has set up a framework for competitive power markets and the opportunity for customers to change the power provider easily. Yet the electricity generation markets have been slow to liberalize.[16]

The European Framework of Emission Regulation

The European Union (EU) launched a carbon market to trade emission certificates within Europe by implementing a European Trading Scheme (ETS) in 2005. The ETS is part of the EU strategy aiming at cost-efficient emission reductions for companies and to fulfill the European climate objectives.[17] Different industry sectors, namely the energy industry, refineries, coke oven plants, steel, cement, glass, ceramic, pulp and paper are obliged to the ETS regulation. Utility firms clearly dominate the other industries in terms of allocated certificates, as they emit the largest amount of carbon. The first phase of the ETS covering the period from 2005 to 2007 served as trial period. While in the first phase emission allowances were allocated freely, the allocation mechanism has changed in the second phase (2008 until 2012). According to the EU Directive, 10 percent of the total emission budget for utilities should be auctioned. For the period 2008 until 2012 the average emission reduction in the EU is set to 8 percent compared to the total emission level in 1990.

In December 2008 the governments of the EU came to a mutual agreement concerning the climate policy after 2012. Currently, the EU's total reduction objective amounts to 21 percent compared to 2005. Starting in 2013 the emission cap will decrease by 1.74 percent annually. Contrary to the first trading periods, the utility sector will have to purchase their need for emission certificates. Yet exemptions do exist mainly for Eastern Europe utilities. Regulatory authorities are obliged to grandfather up to 70 percent of emission allowances to utilities, if one of the following two conditions is fulfilled: Either more than 30 percent of the national power generation is based on a single fossil fuel or the gross domestic product per head is less than half of the average of the EU.[18] For the other industries the regulative environment will be tightened as well. Currently, the aim of the EU is to raise the share of emission auctioning from 20 to 70 percent in 2020. Therefore it is very unlikely that the utility industry as well as other industries, which are part of the ETS, will be able to generate windfall profits. Additionally, the EU plans to incorporate other industry branches, like the shipping and the aviation industry, in the ETS within the next years. Economically speaking, the demand side will soar in the next decade, while the supply side in terms of the total emission cap will decrease annually. The latter will limit the total amount of

[12] See Takashima, R./ Goto, M./ Kimura, M./ Madarme, H. (2008), Entry into the electricity market: Uncertainty, competition, and mothballing options in Energy Economics, Vol. 30, Issue 4, pp 1809-1830.
[13] Roques, F./ Nuttal, W./ Newbery, D. (2006), Nuclear Power: A Hedge against Uncertain Gas and Carbon Prices?, Working Paper, p.19.
[14] IEA (2005), Lessons from Liberalised Electricity Markets.
[15] See Glachant, J. M. (2006): Generation technology mix in competitive electricity markets, in Competitive Electricity Markets and Sustainability, Lévêque, F. (ed.).
[16]See Knight, E. (2008), The Economic Geography of Carbon Market Trading: How legal regimes and environmental performance influence share performance under a carbon market, Working Paper, Oxford University Centre for the Environment.
[17] The ETS is legally based on the EU-Directive 2003/87/EC.
[18] See Kobes, S. (2008), Eckpunkte des EU-Klimapaketes (German language), in Dow Jones TradeNews Emissions, No. 26, December 2008.

emission certificates on the market. As a consequence, the net effect of change demand and supply change will cause higher emission certificate prices.

As long as utility firms are able to pass on the cost of carbon to customers the carbon risk is rather low. However, against the background of a single European electricity market achieving a comparative cost advantage in terms of less carbon by generating electricity becomes more important for utilities in the long run. Therefore utilities operating a power plant park with low emission intensity are better off compared to utilities running plants with high emission intensity.[19] While RWE and CEZ are similar in terms of emission intensities, they comply with different allocation rules set by the European Union. For instance, CEZ benefits of a free certificate allocation in the current second ETS phase and will particularly profit from exemptions of full auctioning in the third trading phase. In contrast, RWE and Iberdrola will be obliged to buy 100 percent of the needed emission certificates in the period of 2013 to 2020. Since Iberdrola operates a power plant park which can be characterized by low emission intensity, we expect Iberdrola to be better off in terms of carbon risks compared to RWE.

Our study comprises utility firms from different areas of Europe. While we conduct our valuation for the largest power generators in the Czech Republic and Germany, we take the Spanish utility firm Iberdrola into account, as their power plant park differs significantly from CEZ and RWE. The sample allows exploring the financial carbon exposure of the specific utility and comparing the equity values. A comparative advantage in terms of low carbon risk in generation should turn out higher equity value.

[19] See Bassen, A./ Rothe, S. (2009), Incorporating CO_2 Risks in Valuation Practice. A Capital Market Approach for European Utilities, in Online Proceedings of the 32nd IAEE International Conference San Francisco, California, USA.

Valuation Model

Based on the earlier discussion on the energy industry in the context of carbon risk, it becomes apparent that investors and analysts require a valuation approach, which enables them to assess potential value at risk on their investment within this sector.

In what follows, we outline our integrated valuation approach that identifies and assesses the complex fundamental drivers of value in a traditional valuation framework. To demonstrate how to incorporate CO_2 risks in capital market orientated valuation practice in the case of the European utility sector, we adopt the following methodology.

Valuation Methodology

Our model is based on a Discounted Cash Flow (DCF) method for plant portfolios of the respective utilities. Since in a DCF valuation future cash flows are discounted to determine the Net Present Value (NPV) of the company's equity, the cost of capital has to be derived first. From our point of view, the incorporation of carbon risks in company valuation should be effected out by adjusting the cost of capital – or to put in other words, the adequate risk-adjusted discount rate.

Thus, in a first step of the valuation procedure we derive the carbon-adjusted cost of capital. For this purpose, we suppose an extended capital market model including carbon as an additional systematic risk factor. We conduct an empirical analysis using capital market data to test our hypothesis: If investors request a premium for carbon risks, an adjustment of firm's equity cost of capital is justified. The analytically derived carbon risk-adjusted costs of capital serve as the adequate discount rates in the following DCF-valuation procedure for RWE, CEZ and Iberdrola.

In a second step we construct a cash flow model for the generation portfolio of the utilities' power plants by modeling free cash flow for each individual plant. As the existing plant portfolios are aging rapidly which leads to a significant capacity replacement, we also account for changes of the power portfolios. Here, we consider the individual investment strategies of the electric utilities. Finally, using our risk-adjusted cost of capital, we discount predicted future cash flows in order to determine a fair company value for RWE, CEZ and Iberdrola.[20]

Step 1: Derivation of Carbon-adjusted Cost of Capital

To ensure transparency and traceability of our valuation procedure, we first motivate the theoretical framework of our capital market approach, to second deduce the empirical analysis. Finally, on the basis of our empirical results, we point at implications for the cost of capital, which are used as adequate discount rate in the following DCF plant portfolio valuation.

Theoretical Foundation

Typically, theoretical capital market models like the Capital Asset Pricing Model (CAPM) are used to determine the risk-adjusted discount rate. The CAPM identifies the fair remuneration for taking on risks on the capital market and derives the equity capital costs of a company. The model postulates a linear relationship between the expected return on an asset and the asset's beta. The beta coefficient is a measure of systematic risk and reflects the business risk in relation to the market risk. However, the CAPM gives no inference on the concrete risk factors that drives the investment return. Multi-factor models on the contrary, are more powerful, as they take various factors (e.g. inflation or energy prices) as sensitivities of stock returns into account and allow for several risk premiums.

We focus on the CAPM market model and augment it in the spirit of a multi-factor model through the addition of a carbon risk factor. Our purpose is to derive carbon-adjusted equity cost of capital that incorporates a fair remuneration for taking on carbon risks. Following capital market theory, we suppose that investors request a risk premium for systematic risk factors. We hypothesize that carbon risks are systematic risks. Hence, from the corporate valuation point of view, a premium for carbon risk has to be

[20] Please, note we focus on generation activity. Therefore we neglect other business activities (i.e. network etc.).

added on the market risk premium known from the CAPM. Here, carbon risk is defined as the sensitivity of changes in carbon returns to stock returns.

Our choice to use carbon returns respectively price returns of emission allowances (EUA)[21] as proxy for carbon risk is motivated by the fact that companies regulated by the EU ETS face new market risks linked to the EUA price formation. Especially electric utilities are forced to include the cost of carbon certificates in their operative decisions for existing power plants, as well as for investment decisions. Hence, price and volume risk of carbon certificates has to be considered. Accordingly, we concretely suppose that price returns of emission certificates are systematic risk factors that drive stock returns on capital markets.

A practical approach requires simplicity. Hence, we concentrate on the pervasive factors, which allow quantifying the carbon risk of a company. Consequently, we focus on the excess returns on the market index (here DJ Euro STOXX) and the excess returns of carbon price changes (here ECX Carbon futures) to cover market risk and carbon risk, respectively. Including these two risk factors in the model, the cost of equity capital expressed as expected return on the utility stock can be estimated. For our analysis we rely on the following methodology, which can be generally expressed as:

$$(1) \quad \mu_i = r_f + \beta_{iM}(\mu_M - r_f) + \beta_{iC}(\mu_C - r_f)$$

According to (1), the expected return of a stock, μ_i, is equal to the risk-free interest rate, r_f, and risk premiums for market risk and carbon risk. The latter are based on stock's sensitivities expressed as β_{iM} and β_{iC} to the market and carbon factors with an expected return of μ_M and μ_C.

Empirical Analysis

Having identified the two risk factors of the capital market model, we start our empirical analysis. The dependent variables are historical electricity stock returns of RWE, CEZ and Iberdrola, which should be explained by two explanatory variables. One is the return of the market index as proxy for the market risk and the other the return of the carbon futures as proxy for CO_2 risks. Consequently, we adjust equation (1) for the simple OLS (Ordinary Least Squares) regression analysis in the following way:

$$(2) \quad r_i = \alpha_i + \beta_{iM} r_M + \beta_{iC} r_C + \varepsilon_i$$

Where:

r_i are logged daily returns for electricity stocks
r_M are logged daily returns for the market portfolio
r_C are logged daily return of emission certificates

ε is the disturbance term. α_i and β_{iM}, β_{iC} are the unknown parameters that have to be estimated by OLS. β_{iM} and β_{iC} capture the market and carbon risk. Analogous to the market beta factor, the carbon beta parameter quantifies the change in stock returns of a firm at a one percent change in returns on emission certificates.

We expect that returns of utility stocks are affected by changes to carbon prices and suppose that the carbon beta coefficient is not zero. In the case of an emission regulation set by a regulatory authority in which all emission certificates have to be bought on markets, windfall profits are avoided. Thus price changes of emission certificates affect the profitability of the utility and hence hit stock returns.[22] This sensitivity is captured by the beta of the carbon coefficient. In a regulatory environment without any free allocation of emission certificates, the carbon coefficient has to be negative for low-emitting utilities and positive for high-emitting utilities.

If power firms have to purchase their total need of emission certificates, power companies operating low-emitting power plant parks are better off compared to high-emitting utilities. Consequently, investors will request a higher premium for investments in high-emitting utilities. In our analysis we question whether capital markets have already anticipated the regulative change and if the carbon

[21] Emission certificates such as Certified Emission Reductions (CERs), Emission Reduction Units (ERUs) and Voluntary Emission Reductions (VERs) are also emerging assets in the carbon markets; because of the particular relevance of EUAs in the context of this study, these markets are neglected here and emission certificates and carbon price are used as synonyms for EUAs and EUA price.

[22] We assume that utilities in competitive energy markets are not able to pass on all costs to costumers.

exposure expressed as beta of the carbon coefficient differs within our sample. Hence we test the following hypothesis:

> *Carbon is a pervasive risk factor for European utilities. Equivalently, the beta of the carbon factor is non- zero.*

Having specified our empirical model and hypothesis to be tested, we use historical data to examine relevant risk factors and to estimate the unknown parameters. Our analysis covers roughly the first trading period of the EU ETS, with a constraint for the very early first phase for which no EUA price data is available. We examine the mentioned three utility stocks of RWE, CEZ and Iberdrola for the sample period of April 22nd 2005 to December 31st 2007 (in total 682 daily data points[23]). The utility stock prices (dependent variable) are taken from Thomson Datastream. Dow Jones Euro STOXX Index acts as market index. We use daily return, which are calculated continuous compounded.

To gain the data for CO_2 certificate prices, we rely on data for emission allowance futures with maturity in December 2008 traded at the European Climate Exchange (ECX).[24] This is the predominant marketplace for EUA futures with a market share of 43 percent in 2007.[25] Due to the design of the different trading phases in the EU ETS, we believe it is more reliable to conduct the analysis with future price data compared to spot market data. The latter collapsed in 2006, when an oversupply of allowances was revealing after the disclosure of verified emissions data in 2005. Finally, spot prices moved towards zero, as verified emissions in 2007 were below the 2006 yearly allocation.[26] Although futures prices were affected from the disclosure as well, they also take expectations of market participants with respect to future regulation into account. Hence, carbon futures are more suitable as proxy for the carbon price risk than spot market data.

Table I presents the results of our regression analysis for the three individual utility stocks. They confirm our expectations that high carbon risk corresponds with an additional risk premium, which raises equity costs causing a lower equity value. In particular for RWE and CEZ, which can be characterized as high-emitting utilities, the beta coefficients for the market index as well as the beta coefficient for carbon are highly significant. This means utility returns can be explained by the market and carbon returns. Both coefficients are positive, stating that investors should request risk premiums for market and carbon risks for those utility firms. Otherwise, our results for Iberdrola state that stocks of the low-emitting utility have lower equity cost, which corresponds to a higher equity value.

Our results show that investors request the highest premium for carbon risk for CEZ compared to other European utilities. CEZ's electricity generation mainly relies on lignite and hard coal. Due to this power generation mix and the separate emission regulation treatment of utilities from Eastern Europe, CEZ benefits from the emission allocation process (please, refer to Section II). Therefore, carbon price increases cause higher returns for CEZ stocks. From the corporate valuation point of view, this implicates that the premium for carbon risk has to be added on the market risk premium. Accordingly higher opportunity cost of equity will lead to a lower equity value, reducing the fair value of CEZ stock.

The generation mix of RWE, similar to the power plant park of CEZ, consists mainly of fossil plants. Consequently, the carbon beta coefficient is statistically significant, confirming the validity to add a carbon premium on the discount rate.

In contrast to RWE and CEZ, the emission intensity of Iberdrola is low. For the Spanish utility we identify a weak negative relationship between carbon prices and stock returns. Thus, higher carbon prices cause lower stock returns of Iberdrola, which leads to lower equity cost and consequently, a higher equity value. This is consistent with our theoretical

[23] Given the short sample period, we believe that daily data is the only adequate frequency to conduct our time series analysis as weekly or monthly data would provide too few observations.
[24] The ECX offer an unrestricted access to EUA price data.
[25] See Daskalakis, G. / Psychoyios, D. / Markellos, R.N. (2009): Modeling CO_2 Emission Allowance Prices and Derivatives: Evidence from the European Trading Scheme, Journal of Banking & Finance (Forthcoming).
[26] See Alberola, E. / Chevallier, J. / Chèze, B. (2008): Price drivers and structural breaks in European carbon prices 2005-2007, Energy Policy, 36(2), S. 787-797.

Table 1: Regression results

Dependent Variable	Intercept		Market Portfolio		Carbon		R^2
	Coefficient	t-Statistic	Coefficient	t-Statistic	Coefficient	t-Statistic	
RWE	0.0006	1.5340	0.7261***	14.978	0.0457***	3.3075	0.26
CEZ	0.0012*	1.7808	1.1021***	13.945	0.0569**	2.5252	0.23
Iberdrola	0.0005	1.3295	0.8430***	17.683	-0.0066	-0.4877	0.32

* and ** and *** indicate significance at 10%, 5% and 1% levels respectively

explanations. While a clean power generation mix is one possible explanation, the characteristics of the Spanish power market is another. Compared to other European power markets, the Spanish power generation market is rather competitive.[27] However, please notice that the carbon coefficient is statistically insignificant.[28]

We conclude with some remarks on the regression analysis and potential extensions that underline the robustness of our findings:[29]

First, using an extended sample period including EUA future price data of 2008 (i.e. the second ETS phase), we identify a highly significant impact of carbon on utility stocks. In fact, the interaction of EUA price changes and utility returns is even more pronounced by a higher carbon beta[30]. Hence, in future the carbon exposure of utilities might gain in importance.

Second, we extend our regression analysis with various energy variables – namely oil, gas and electricity price changes – to control for potential biases. This inclusion is motivated by the fact that fuel prices are important determinants of carbon prices. Therefore, the exclusion of energy price variables – as well as of electricity price variables that are affected by the EUA prices themselves – may cause severely biased estimates with respect to the effect of EUA price changes on utility stock returns. Including these control variables we still identify widely stable and significant carbon betas (except for Iberdrola).

Derivation of the cost of capital

Having determined the fair remuneration for taking on carbon risks in terms of the carbon betas, we use our empirical results to derivate adequate risk-adjusted discount rates for the company valuation of RWE, CEZ and Iberdrola.

Within the DCF valuation techniques, we rely on the commonly used Weighted Average Cost of Capital (WACC) method. Yet we calculate the carbon-adjusted Weighted Average Cost of Capital. To determine the respective WACC, we have to calculate its three components: the cost of equity, the (after-tax) cost of debt and the company's target capital structure. Since none of the variables is directly observable, we have to estimate each component.

$$(3)\quad WACC = \frac{D}{V}(1-t)r_{Debt} + \frac{E}{V}r_{Equity}$$

Where: D/V = Target value of debt to enterprise value using market-based values
E/V = Target value of equity to enterprise value using market-based values
r_{Debt} = Cost of debt
r_{Equity} = Cost of equity
t = Company's marginal income tax rate

First, following equation (1), the cost of equity capital is calculated as the sum of the risk-free interest rate and risk premiums for market and carbon risks:

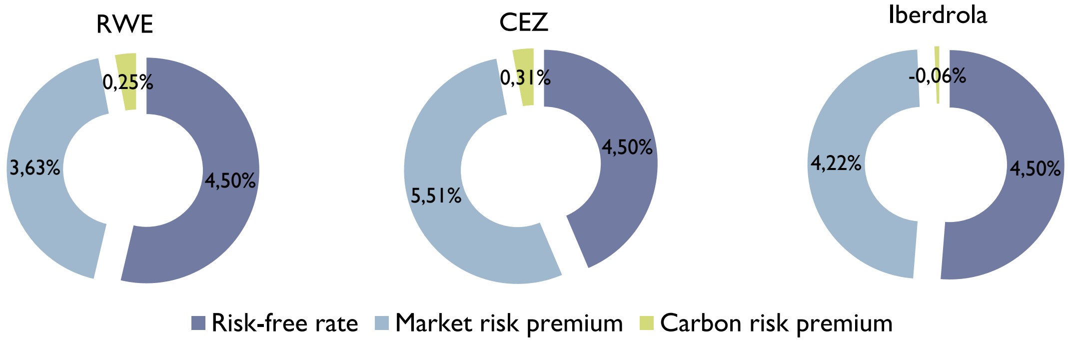
$$(4)\quad r_{iEquity} = r_f + \beta_{iM}(r_M - r_f) + \beta_{iC}(r_C - r_f)$$

In practice, the risk-free interest rate is usually approximated by local government bond yields. The market risk premium is calculated by measuring and extrapolating historical excess returns. We recommend estimating the carbon risk premium in a similar way by extrapolating the carbon excess returns. We assume a market risk premium of 5 percent, a carbon risk premium of 5.5 percent[31], and

[27] Please, refer to Section II.
[28] Although, we use our empirical results for the following cost of capital calculation.
[29] For simplicity the data and results are not presented in detail in this report but they are available on request.
[30] Please, note that this is valid only for RWE and CEZ. The carbon beta of Iberdrola remains insignificant.

[31] We calculate the annualized average daily returns of ECX EUA Future with maturity 2008 from April 22nd 2005 to December 31st 2007, which is 10 percent. To gain excess return we deduct the risk-free interest rate of 4.5 percent.

Figure 1: Composition of equity cost of capital



a risk-free rate of 4.5 percent. For the beta coefficients we use our estimation of the empirical analysis (please refer to Table 1)[32].

In that case RWE's equity cost of capital will amount to:

$$r_{Equity}^{RWE} = r_f + \beta_{RWE\_M}(r_M - r_f) + \beta_{RWE\_C}(r_C - r_f)$$

$$r_{Equity}^{RWE} = 0.045 + 0.726 * 0.050 + 0.046 * 0.055 = 0.084$$

According to equation (4), carbon-adjusted equity costs of RWE amount to 8.4 percent. Roughly speaking, 3 percent of RWE's equity costs refer to the carbon risk premium. The equity costs of CEZ and Iberdrola are calculated analogously.

Figure 1 depicts carbon premiums as share of the adjusted equity cost of capital, which clarify that the carbon intensive utilities RWE and CEZ are punished by higher equity costs, while Iberdrola with a clean power plant park benefits of a marginal equity cost discount[33]. From these results, it appears that by all means it is worthwhile to enhance conventional valuation techniques. The merit of the applied capital market valuation approach is to detect and assess essential costs of carbon risk.

Second, to approximate the after-tax cost of debt we use data from company's annual reports. Finally, the target capital structure is also approximated by ratios the companies refer to in their respective corporate information.

Table 2 summarizes assumed values for the three WACC components and the calculated carbon-adjusted WACC, which explicitly accounts for carbon risks of utilities in the course of the EU ETS.

Table 2: Weighted Average Cost of Capital

RWE		CEZ		Iberdrola	
Risk-free rate	4.5%	Risk-free rate	4.5%	Risk-free rate	4.5%
Market risk premium	5.0%	Market risk premium	5.0%	Market risk premium	5.0%
Market Beta	0.726	Market Beta	1.102	Market Beta	0.843
Cost of Equity	8.1%	Cost of Equity	10.0%	Cost of Equity	8.7%
Carbon risk premium	5.5%	Carbon risk premium	5.5%	Carbon risk premium	5.5%
Carbon Beta	0.046	Carbon Beta	0.057	Carbon Beta	-0.01
adj. Cost of Equity	8.4%	adj. Cost of Equity	10.3%	adj. Cost of Equity	8.7%
Cost of Debt after tax	4.6%	Cost of Debt after tax	5.0%	Cost of Debt after tax	5.1%
Equity (%)	50%	Equity (%)	55%	Equity (%)	53%
Debt (%)	50%	Debt (%)	45%	Debt (%)	47%
adj. WACC after tax	6.5%	adj. WACC after tax	7.9%	adj. WACC after tax	7.0%

[32] Please, note that for simplicity we forbear to adjust the beta coefficient for capital structure risk by unlevering and relevering.

[33] Please, notice again that the carbon coefficient of Iberdrola is almost zero and statistically insignificant.

Step 2: Valuation of Power Plant Portfolio

Model Setup

The company value of the European utilities we analyze in our study is fundamentally determined by the value of their power plant portfolio. Hence, to conduct our DCF valuation with the analytically derived WACC as discount rate, we model the power generation capacity of the utilities in order to forecast future cash flows. Our forecast period from 2009 to 2020 covers the second and third trading period of the EU ETS. Beyond the explicit forecast period we estimate the continuing value of the respective utility. The constructed power plant portfolios of the utilities compromise the existing plant park, as well as the announced investment portfolio of the energy supplier.

First, we model existing power plant portfolios and technical parameters of different plant technologies. We suppose that technical plant characteristics keep constant over time. Then we assume an economic lifetime for each existing plant.

Second, we model a replacement investment for each existing plant at the end of its estimated economic lifetime in form of a new build plant. Additionally, we estimate the increase in the capacity of overall power generation. This enables us to dynamize our plant model and to account for future investment decisions and their influence on the utilities' equity value.

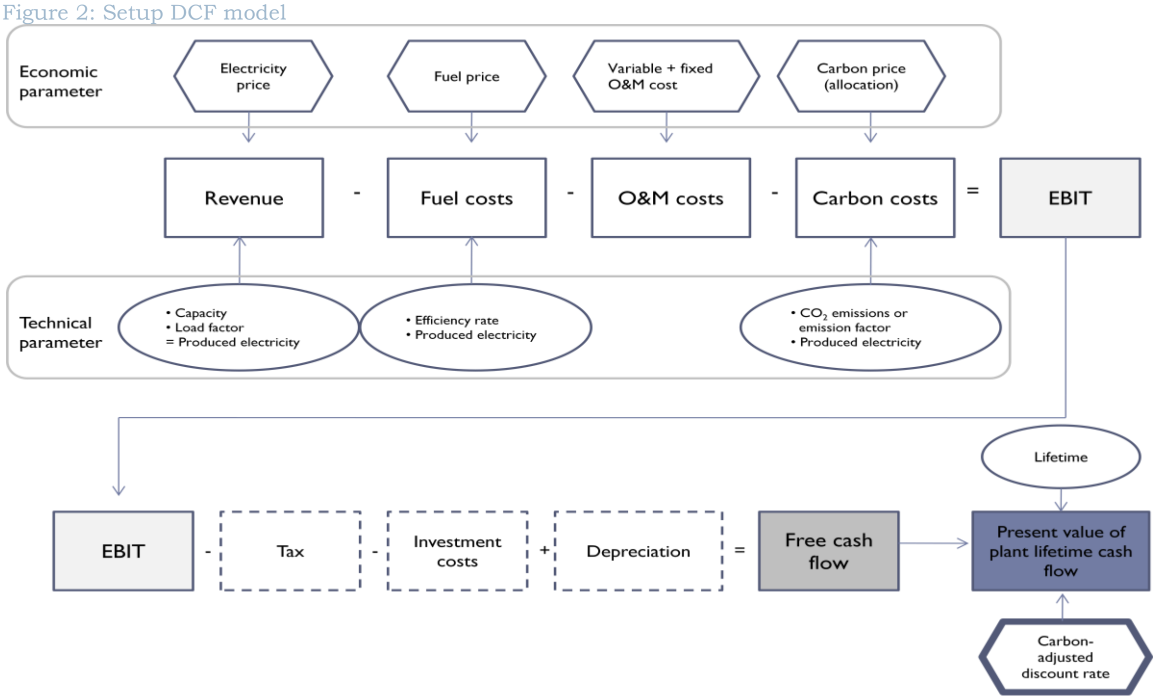
Having specified our plant model in terms of technical attributes of existing and future power plants, we introduce economic parameters to forecast future plant cash flows. In detail, we make assumptions for electricity, fuel and EUA prices, as well as for operation and maintenance (O&M) costs and investments cost for the different technologies.

Using these economic and technical parameters, we can finally calculate cash flows of each power plant over the remaining lifetime. Considering taxes and depreciation, we obtain estimated free cash flows, which are discounted with the derived carbon-adjusted WACC to calculate fair values.

Figure 2 depicts the DCF model setup schematically.

At this point, please notice that the effort to model cash flow for each power plant and not aggregated for generation technologies is justified. First, this enables us to comprehensively study dependencies of corporate value on plant technology, investment strategy and future carbon regulation. Second, as the existing plant portfolio is relative stable over time, underlying plant data need not to be updated frequently.

Figure 2: Setup DCF model



Power Plant Portfolio

We construct plant portfolios for RWE, CEZ and Iberdrola that in principle compromise the whole generation capacity of the utility. These generation portfolios consist of fossil (i.e. coal, gas, oil) and non-fossil power plants (water, wind, solar and nuclear). We do not take non-owned contractually secured plants into account.

The construction of the plant portfolio and derivation of technical parameter are based on 2008 data from energy information provider Platts. These provide fuel type, gross capacity and commissioning year of existing plants. In addition, we use the EU's Community Independent Transaction Log (CITL) to gain reliable and non-biased data on CO_2 emissions of the power plants in 2008. The CITL is the official European registry of the EU ETS and publicly records the verified emissions for every installation covered by the EU ETS.

On that basis, all other technical parameters of the plants portfolio are derived and we assume that all plant characteristics keep constant over time. Based on the internal electricity consumption (percent of gross capacity) we derive the net capacity of plants. We individually determine the plant position in the merit order and the load factor for each plant. Power plants in the base load are assumed to operate 8,760, mid-merit plants 6,000 and peak plants 1,000 annual operating hours. Here we use an annual utilization rate of 90 percent for plants to take downtime related to scheduled maintenance etc. into consideration. Notwithstanding, for renewable energy plants we assume that only 50 percent of annual operating hours are realized, as these technologies are amongst others weather-dependent.[34] Using the derived load factor and net capacity, we calculate electricity generation per year measured in mega watt hours (MWh).[35] Furthermore, we define efficiency rates for state of the art technologies. As the actual efficiency is a function of plants age, we assume a gradual decline of efficiency subject to the age (see adjustment rate in Table 3).[36]

Table 3 Efficiency Rate

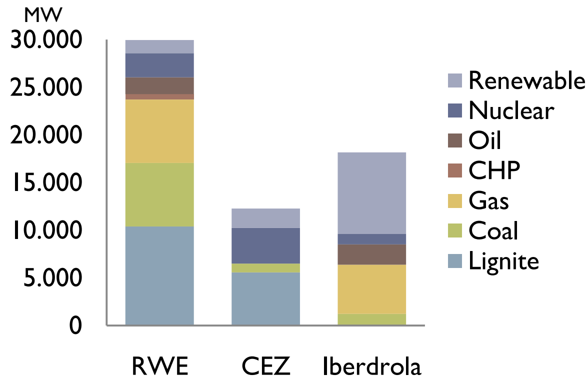
Technology	Efficiency rate	Adjustment rate
Coal	46%	0.25%
Lignite	43%	0.25%
Gas	58%	0.10%
CHP*	80%	0.10%
Nuclear	35%	0.20%
Water	85%	0.00%
Wind	45%	0.05%
Other	35%	0.10%

Source: EWI/EEFA (2008), p. 20; Erdmann/Zweifel (2008), p. 300; own assumptions
*CHP = Combined heat and power

Altogether we analyze 67 fossil and nuclear plants and 392 renewable plants with a capacity of 60,405 MW. The accumulated generation capacity of the RWE, CEZ and Iberdrola portfolio is respectively 29,958 MW, 12,271 MW and 18,176 MW, representing 96.7 percent[37], 99.8 percent[38] and 86.1 percent[39] of total existing capacity.

Figure 3 illustrates the reproduced power plant portfolios of RWE, CEZ and Iberdrola split on fuels in percentage terms of MW capacity.

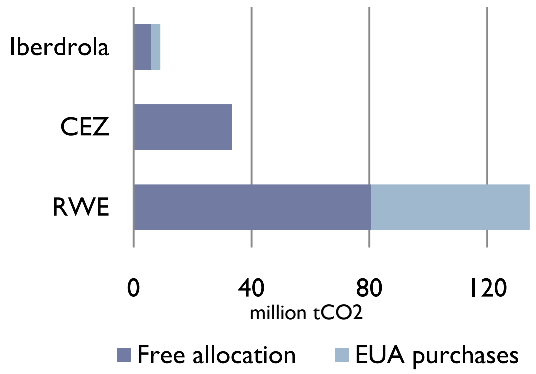
Figure 3: Generation capacity by fuel (2008)



[34] We are aware of the fact that particularly wind energy capacity operates less. However, our results for equity values are barely affected by this assumption.
[35] To ensure a realistic reproduction of the utility generation mix, we use availably company information to check consistency of modeled and real power plants in terms of capacity and power generation.
[36] For simplicity, we do not account for technological developments in terms of improvements in efficiency rates.
[37] Portion related to capacity of owned plants of RWE Group. RWE's owned plants account for 65 percent of total capacity including contractually secured plants.
[38] Portion related to capacity of CEZ power plants in Czech. These account for 86 percent of CEZ's total capacity. We do not model other international CEZ plants.
[39] Portion related to capacity of Iberdrola's total Spanish capacity, which make up 49 percent of the group capacity. We confine ourselves to model just the Spanish generation capacity.

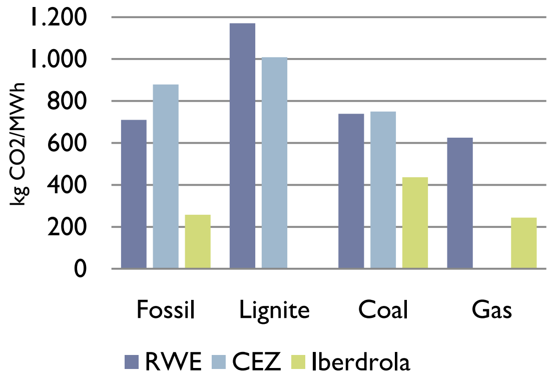
The generation mix of RWE and CEZ mainly relies on lignite and hard coal, representing 57 and 52 percent of the generation capacity in 2008, respectively. Plants based on coal and lignite technology account for the lion's share of their CO_2 emissions (93 percent for RWE and 100 percent for CEZ). In contrast, the generation mix of Iberdrola is dominated by renewable technologies (47 percent). In particular the share of CO_2 intensive coal plants is low (7 percent) and flexible gas plants represent the favored fossil technology of the Spanish utility (28 percent). If we also take nuclear plants into account, Iberdrola and CEZ are characterized by a CO_2-free capacity of 53 and 47 percent, while RWE's share of clean capacity is 13 percent. Figure 4 shows the total amount of CO_2 emissions in 2008 for the utility plant parks based on CITL data.

Figure 4: Carbon emissions (2008)



The CO_2 intensity by fuel is given in figure 5, showing the average CO_2 emissions in kilograms per MWh produced for the model portfolio of RWE, CEZ and Iberdrola.

Figure 5: Carbon Intensity by fuel (2008)



Finally, we illustrate the age structure of the utility plant portfolio in figure 6. The modeling of the existing lifetime of plants and the corresponding expiring lifetime curve for the model portfolios are based on plant-specific assumptions on remaining lifetime (see following paragraph). As it can be seen, the existing capacity drops dramatically over the next 5 to 10 year. This is especially true for RWE. Due to the high average age of notably coal plants, we state massive investment needs to hold up generation capacity. Hence, we develop a replacement investment strategy for retiring existing plants to allow for these circumstances.

Replacement and Investment Strategy

We assume for each existing power plant an economic lifetime, which varies by plant technology. Table 4 summarizes our assumptions for power plants, which are geared to average practice values and therefore lie above typical technical lifetimes. Simplifying, we assume an infinite life for renewables. Furthermore, we suppose nuclear plants can still operate in our forecast period.[40] Therewith we determine the replacement year when an existing old plant is replaced by a new one.

Table 4: Economic plant lifetime

Technology	Lifetime
Coal	45
Lignite	45
Gas	40
Oil	35
CHP	35
Nuclear	40
Renewables*	100
Other	35

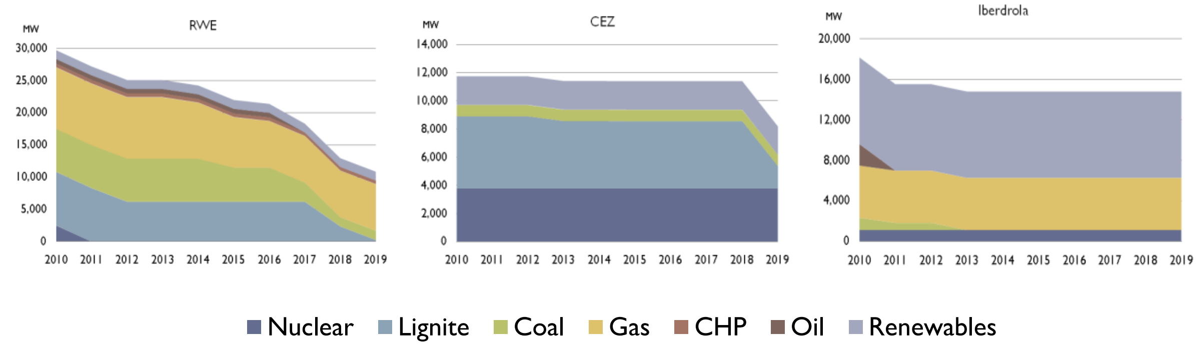
Source: dena (2009), p. 3
* own assumptions.

We model for each existing power plant at the end of the estimated economic lifetime a new replacement plant that inherits the same gross capacity. The replacement investment decision in

[40] For German nuclear plants we assume that they will be phased out in line with current German legislation. Still we suppose new nuclear plants can be build by RWE (e.g. in UK).

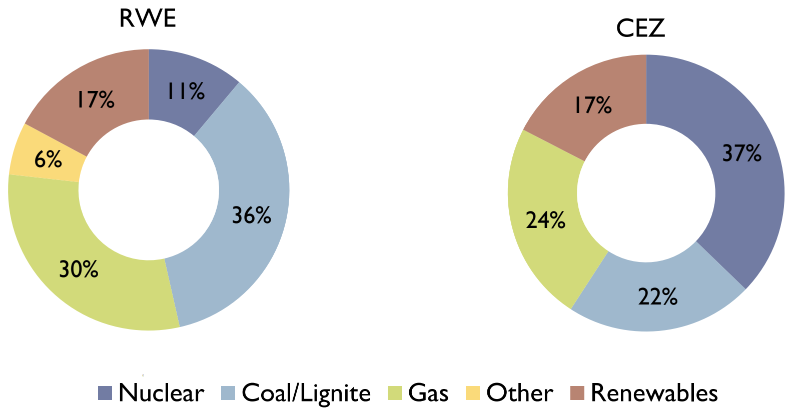
terms of the fuel technology choice is determined by the communicated target generation mix of each utility for the year 2020. Hereby, we account for the strategic orientation of the utilities in the tightening regulatory environment of the EU ETS. Figure 7 shows the target generation portfolio of RWE and CEZ. Iberdrola does not explicitly state its target mix, but declare a significant reduction of coal and the stabilization of renewable power as priority energy source, with nuclear power plants in the base load as company targets.

Figure 6: Expiring lifetime curves



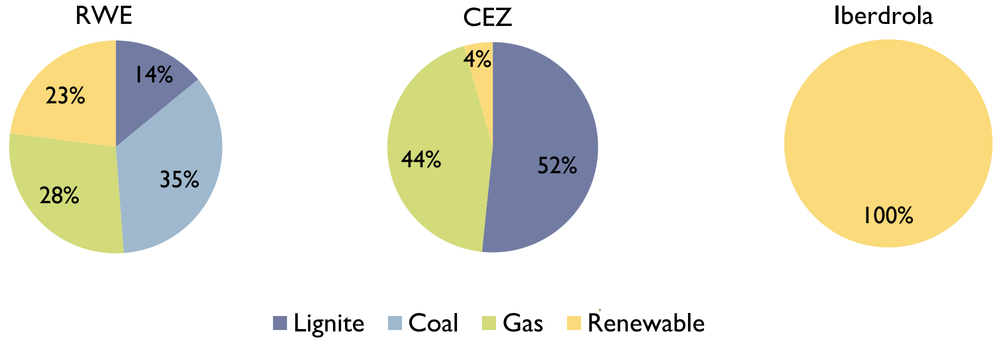
The targets of RWE and CEZ both imply a significant reduction of coal-fired plants in favor of gas-fired plants and renewable energy. In addition, the targets of all utilities imply that nuclear power remains as sustainable option in the generation mix. Although this might be at odds with current German legislation of nuclear phase out, we assume that the energy suppliers are able to achieve their vision fuel mix.

Figure 7: Utility target portfolio in 2020



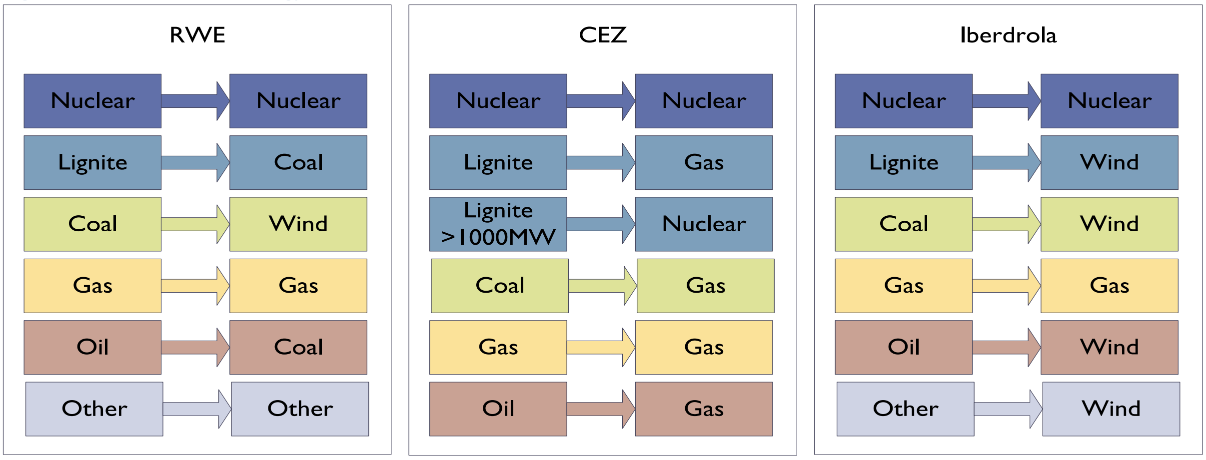
Consequently, we develop investment plans for replacement plants, which secure that target portfolios are achieved. This plan also considers the target capacity for the year 2020 and hence the future capacity building of the utilities (RWE +30 percent; CEZ +16 percent; Iberdrola +14 percent). In detail, first those replacement plants are realized, which are currently constructed or in plan according to the Platts database. Figure 8 illustrates the pipeline of new plants for RWE (16,114 MW), CEZ (2,731 MW) and Iberdrola (1,171 MW).

Figure 8: Capacity of pipeline plants by fuel



The replacement plants beyond that are replaced by prototypical new plants according to the following rules resulting from the utility investment strategy (figure 9):

Figure 9: Investment strategy



Technical parameters of new power plants are determined along the lines described above. For replacement plants based on renewable energy, we simplifying suppose that these are wind plants. The unknown future CO_2 emissions of new plants are calculated by means of specific CO_2 emission factor for primary energy carrier (Table 5).

Figure 11 illustrates the modeled capacity generation mix of the plant portfolio in 2020 for RWE, CEZ and Iberdrola, which are consistent with the utility vision fuel mix.

Each 2020 plant portfolio is characterized by an increasing share of CO_2-free generation capacity, whereas the expansion of CEZ is rather moderate and that of RWE is more than doubling (Figure 10). We assume that the utilities continue their business with the illustrated plant portfolio after the year 2020.

Table 5: CO_2 emission factor by fuel

Fuel	CO2 emission factor (tCO_2/MWh)
Coal	0.33
Lignite	0.40
Gas	0.20

Source: UBA (2005), S. 109

Figure 10: Share of CO_2-free capacity

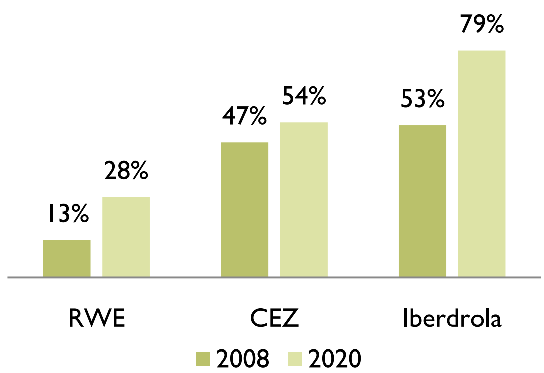
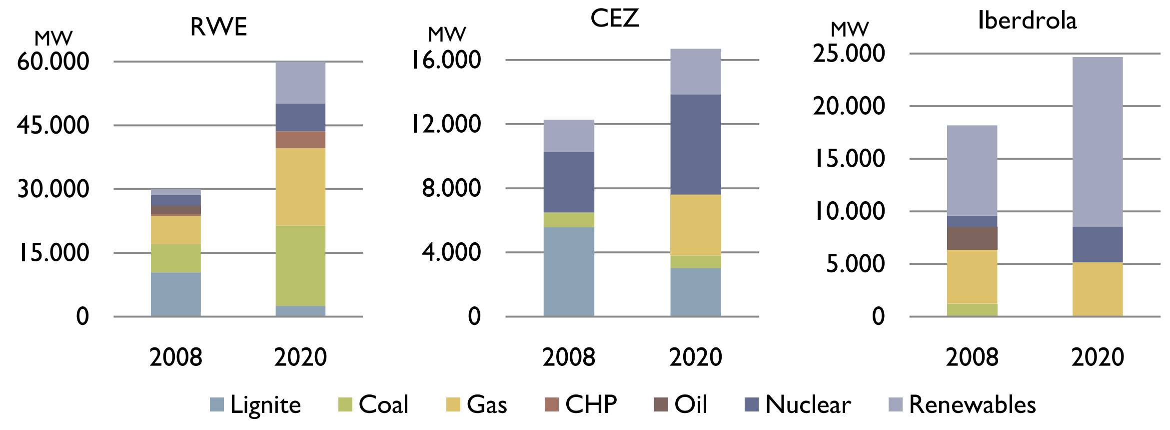


Figure 11: Development of capacity generation mix



Economic Parameter

Having specified the model plant portfolio and associated production-technical parameters, we set out our economic parameters needed for the cash flow calculation of plants. On the revenue side, this is the electricity price. On the cost side, these are fuel and EUA price, as well as variable and fixed O&M costs. Additionally, for new build plants investment costs incur. Depreciations are also taken into consideration.

Table 6 and figure 12 summarize our commodity price assumptions.

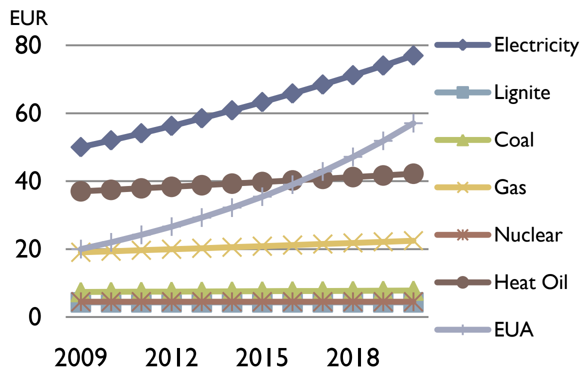
Table 6: Commodity price assumptions

Commodity	Price 2009	Growth rate p.a.
Electricity Base Load (EUR/MWh)	50.00	4.00%
Electricity Peak Load (EUR/MWh)	75.00	4.00%
Lignite (EUR/MWh)	4.32	0.00%
Coal (EUR/MWh)	7.38	0.50%
Gas (EUR/MWh)	19.08	1.50%
Nuclear (EUR/MWh)	4.50	0.00%
Heat Oil (EUR/MWh)	37.00	1.20%
EUA (EUR/tCO_2)	20.00	10.00%

Source: EEX; EWI/EEFA (2008), p. 12f.; IEA (2007), p. 4; Prognos/EWI (2007), p. 109.

Underlying electricity prices are derived from historical data of the European Energy Exchange (EEX) for the period of 2006 to 2008. The related annual growth rate is calculated with the corresponding EEX Phelix Year Future for 2012.[41]

Figure 12: Commodity prices



Fuel price assumptions are mainly based on recent studies of EWI/EEFA[42] and IEA[43]. We use high price scenarios, which suppose high crude oil prices and therefore also high prices for natural gas (oil-based pricing).

We are using a price for EU Emission Allowances of EUR 20/tCO_2, in line with the historical mean of EUA Futures in 2008. This price is higher than the recent low price level, which is ascribed to the persisting financial crisis. However, we suppose that beyond the economic downturn and against the

[41] Our commodity price assumptions implicitly factor in a moderate passing through of the market value of emission allowances causing higher electricity prices (via the relationship of EUA and electricity price growth). However, please notice that for simplicity we do not model specific and empirical justified cost transfer factors for each utility.
[42] See EWI / EEFA (2008): Studie Energiewirtschaftliches Gesamtkonzept 2030, Köln und Berlin 2008.
[43] See IEA (2007): IEA Energy Technology Essentials - Nuclear Power, Paris 2007.

Table 7: Cost parameters by technology

Cost parameter	Lignite	Coal	Gas	Nuclear	Water	Wind	PV*	Biomass	CHP	Oil
Capital Investment Costs (EUR/kW)	1,350	1,200	650	2,100	5,900	1,300	3,500	2,300	1,170	650
Variable O&M Costs (EUR/MWhel)	1.0	1.0	0.7	2.0	0	0	0	0	2.1	0.7
Fixed O&M Costs (EUR/MW/year)	25,000	20,000	15,000	70,000	60,000	45,000	30,000	115,000	56,000	15,000

Source: EWI/EEFA (2008), p. 20; NEA/IEA (2005), p.121

* PV = Photovoltaic

background of the European reduction target of 20 or 30 percent, the fundamental price of EUA is higher and will increase. In order to meet the tightening CO_2 regulation in the EU ETS, we thus assume a carbon price until 2020 of almost EUR 60, which equates an annual growth rate of 10 percent.

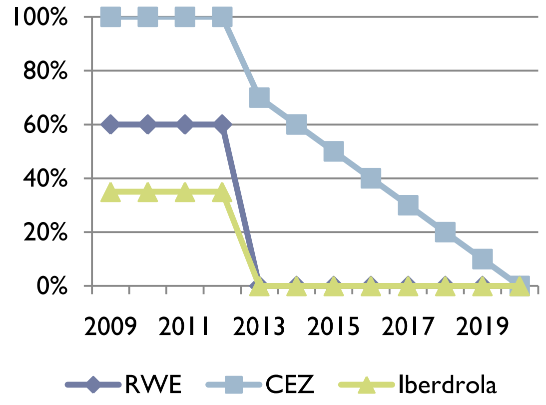
Furthermore, to calculate carbon costs we have to take the allocation of emission certificates in the EU ETS into account. Especially for phase II we have to distinguish national allocation rules (please, refer to Section II). As we do not want to model the NAP rules of every country where the particular power plants are located, we use company information about the share of free allocated certificates to consider the EUA allocation. These are illustrated in Figure 13, showing that especially CEZ benefits of free allocation.

Variable and fixed O&M cost and investment costs of the different power plants are as well derived from recent studies on levelised costs[44] and are summarized in Table 7. They should be understood as average values for power plants. Investment cost of a new plant will hit the plant's cash flow the year before operation.[45] We assume that plant's investment costs are depreciated linear over a unique amortization period of 20 years. We also calculate depreciations for existing plants if the amortization period is not passed.

DCF Valuation

Finally, we use the defined technical and economical parameters of our model plant portfolio to calculate cash flows for each power plant.

Figure 13: Share of free EUA allocation



First, we calculate plant's annual earnings before interest and tax (EBIT) in the years 2009 to 2020 of the forecasting period:

Revenue electricity sales

= *Electricity production (MWh/a)*

* *Electricity price (EUR/MWh)*

- Fuel costs

= *Electricity production (MWh/a)*

/ *Efficiency rate (%)*

* *Fuel price (EUR/MWh)*

- Carbon costs

= *CO_2 emissions (tCO_2)*

* *[1 - share free EUA allocation](%)*

/ *EUA price (EUR/tCO_2)*

- Variable and fixed O&M costs

EBIT

Then we calculate annual free cash flow (FCF) of each plant, whereby we assume a tax rate of 30 percent:

[44] See NEA / IEA (2005): Projected Costs of Generating Electricity. 2005 Update, Paris 2005.

[45] For simplicity, we resign potential decommissioning costs.

	(1-tax rate) * EBIT
+	depreciation
-	investment costs[46]
	Free Cash flow

The sum of each plant's annual cash flow of the respective utility provides the annual utility FCF for our forecast period from 2009 to 2020. As we suppose that the utilities continue their business with the illustrated plant portfolio beyond the explicit forecast period after 2020, we additionally calculate the continuing value of the respective utility. Here, we expect that the net cash flow[47] of the year 2020 will rise with a constant long term growth rate of 0.5 percent. Thus the continuing value (CV) is the present value of a perpetuity.

Our last DCF input variable is the derived carbon-adjusted WACC of the utility, which we use as adequate discount rate for estimated FCF for the years 2009 to 2020 and CV of the utility (Table 2). After all, the enterprise value for utility i can be calculated with the DCF formula:

$$(1)\quad W_i = \sum_{t=1}^{12} \frac{FCF_t}{(1+WACC_i)} + \frac{1}{1+WACC_i} \cdot \frac{FCF_{12}(1+0.005)}{WACC_i - 0.005}$$

To calculate the equity value from the enterprise value we subtract company's net liabilities (including nuclear accruals). Finally, we calculate the value per share by dividing total equity value by the number of shares outstanding.

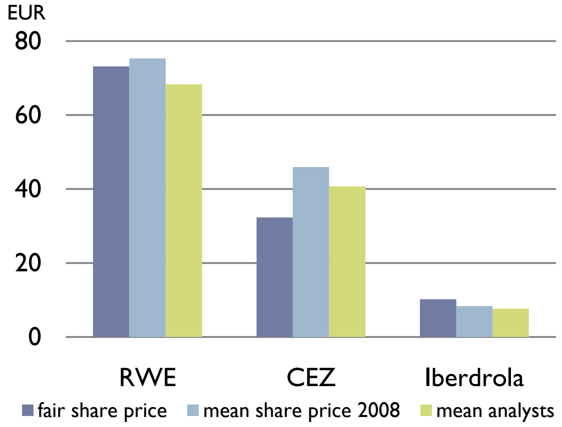
Results

Based on our assumptions and the simultaneous consideration of utility's investment strategy until 2020, the value of the power generation assets amounts to an equity value of EUR 39.4bn for RWE, EUR 19.1bn for CEZ and EUR 50.9bn for Iberdrola[48], representing a fair share price of EUR 73.1, EUR 32.3 and EUR 10.2.

[46] Here we assume that the change of working capital and accruals is zero.
[47] Assuming investment costs in the amount of depreciations.
[48] Since we have focused our analysis on the Spanish generation capacity of Iberdrola, we apply a sum-of-the-parts valuation with broker consensus DCF values for the other business areas of Iberdrola.

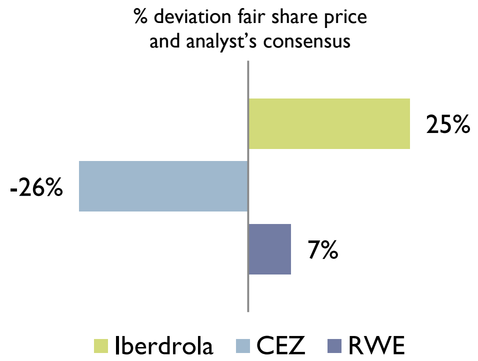
Our results for the fair share price of RWE, CEZ an Iberdorla are presented in Figure 14. As this figure shows, the fair value based on our valuation approach significantly differs from the mean share price in 2008, as well as analyst's consensus.

Figure 14: Results



Comparing the deviation of fair share price and analyst's consensus (Figure 15), our valuation model indicates that based on sound commodity price assumptions and utility's strategic direction, especially CEZ shares are currently overvalued, while Iberdrola shares are undervalued. In contrast, the RWE share value seems to be only slightly undervalued.

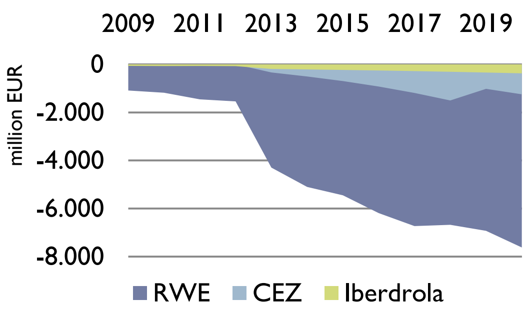
Figure 15: Over- and undervaluation based on fair value



At this point, using the example of CEZ's company valuation, we can point out the merits of our valuation approach.

Our negative results for CEZ might be remarkable given that CEZ benefits from a generous emission certificate allocation, which comes along with significant lower carbon costs in the cash flow calculation (Figure 16). However our valuation model does not solely consider carbon risk via the free cash flow planning but also via the adequate risk-adjusted discount rate. As the latter, in form of CEZ's carbon-adjusted WACC, is significantly affected by a high carbon risk premium investors request, the company value of CEZ is penalized by higher cost of capital.

Figure 16: Trend of carbon costs



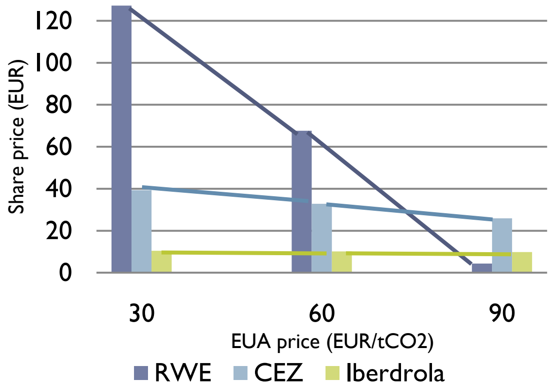
In contrast Iberdrola with a clean power generation mix and a strategic focus on CO_2-free technologies is clearly better off. In our valuation model the utility specially benefit from low cost of capital due to a slightly negative carbon risk premium.

Hence, from the corporate valuation point of view, the premium for carbon risk related to the high emission intensity of CEZ's generation portfolio leads to a lower equity value, reducing the fair value of the CEZ stock. Existing valuation approaches for carbon risks, which rather adjust cash flows of a firm as discount rates, neglect this effect triggered by interactions between capital markets in terms of stock returns and price returns of emission certificates.

Please note that our results are based on a constant load factor depending on the individual plant position in the merit order (please refer to p. 14). In particular, we assume that the produced electricity output is marketable and implicitly that electricity demand will not decline. In future, the merit order position of plants might change which could bring lower operating hours of the plants. Clearly, lower load factors of power plants would lead to lower equity values and share prices. However, as this report concentrates on carbon risks, we neglect to model the demand side dynamics.

Finally, we conduct a sensitivity analysis for the parameter EUA price, which enables us to assess corporate value at risk from carbon price risks. The sensitivity of utility share price for different carbon permit prices for RWE, CEZ and Iberdrola is shown in figure 17.

Figure 17: EUA price sensitivity of share price



The analysis clearly manifest that the EUA price exposure of RWE relative to CEZ and Iberdrola is by far the highest. The RWE stock value is most sensitive to the EUA price level, which is consistent with the high share of CO_2-intensive power plants, which causes a significant financial burden in the course of EU ETS full auctioning of emission certificates from 2013 on.

At a prudential EUA price range between EUR 60 and EUR 30 we calculate a 47 percent reduction of the share value. This can be interpreted as the carbon value at risk of RWE. The results stress once more the importance of carbon price risk for corporate value. If carbon prices approach a level of EUR 90 in 2020, the RWE stock would be even less valuable than CEZ and Iberdrola shares. The latter in contrast show almost no EUA price exposure, as can be seen from figure 17. At EUR 60 vs. EUR 30 we calculate a 3 percent share price reduction.

Conclusion

The aim of our study is to extend conventional valuation methods in order to incorporate CO_2 risks in valuing utilities in particular. We opt for a valuation methodology based on capital market theory and introduce an approach for adjusting equity cost of capital for company specific carbon risk to incorporate carbon risks into company valuation. Using a capital market approach, we do not just investigate cash flows with regard to CO_2 emissions and prices but CO_2 risks are incorporated by adjusting the appropriate risk-adjusted discount rate.

The valuation exercises in this study demonstrate that the use of a capital market model in the valuation process is a practicable and so far an unused option to take carbon risks into account. Our approach presents an extension of the wide used CAPM and can easily be implemented in a traditional DCF valuation process. Such an approach is objective and therefore inter subjectively verifiable.

We show that a high carbon risk corresponds with an additional risk premium, which raises equity costs causing a lower equity value. We strongly advice to take this interactions between capital markets in terms of stock returns and price returns of emission certificates into account. While investors should add the carbon risk of a utility to their required risk premium for valuation, utilities need to know their carbon exposure in order to define future investment strategies.

In the case of RWE and CEZ, our valuation exercises demonstrate the significance of carbon exposure for valuation in a future with stricter regulations. The results underline the necessity to incorporate carbon risks into corporate valuation. On the other hand, the case of Iberdrola indicates that value at risk from carbon is significantly reduced by an active strategy towards a CO_2-free generation mix.

Our approach is not limited to the energy industry. Yet, it is transferable to other industries covered by the EU ETS. The presented capital market framework can simply be used to identify carbon betas as objective carbon risk measure for different industries. Especially, the aviation industry, which will be included in the EU ETS from 2020, could face substantial investment needs in order to modernize the airplane fleet. Hence, a valuation approach that models FCF for each airplane and considers respective replacement strategies – along the lines described above – might be necessary to assess potential carbon risks in the aviation industry.

Based on our findings, we would encourage investors and financial analysts to take these aspects into consideration, and in particular to enhance their valuation models to incorporate carbon risks by a capital market perspective. From our point of view, those investors, who opt for a similar capital market approach as we proposed here, will be at the forefront of identifying and assessing value at risk from carbon exposure. Hence, investors should capitalize the advantages of this so far unused valuation option for carbon risks.

Appendix

Carbon Risk in Current Valuation Practice

One current method to incorporate carbon risks into valuation is the use of ratios relating direct and indirect carbon emissions to a monetary unit of choice (such as turnover or EBITDA). Such ratios are often termed carbon exposure. For example, Société Générale (2007)[49] uses such an approach. In a first step the carbon intensity (g CO_2/USD turnover) of a company is calculated. Applying assumptions on carbon prices and a certain level of free allocation, the computed carbon intensity is translated into a maximum turnover-related carbon exposure. Finally, this monetary value of emissions is applied to EBITDA in order to obtain the potential EBITDA carbon risk exposure (here the ability of cost transfers to suppliers and/or customers is also considered).

In contrast, Carbon Trust and McKinsey (2008)[50] deploy a Discounted Cash Flow (DCF) model to integrate carbon risks. The authors adjust company cash flows to take emissions regulation into account. In detail, they assess cash flows in three scenarios: a business-as-usual scenario, a scenario involving the greatest degree of change executives can now imagine, and a scenario that many scientists believe would be required to stave off a high likelihood of catastrophic climate change-related events. In each scenario four value drivers (carbon costs, regulation changes, technology shocks and consumer behavior changes) that can impact a company directly are investigated to forecast carbon-adjusted cash flows for the DCF valuation.

SAM and WWF (2006)[51] also use a DCF model to analyze corporate value at risk from carbon for the German utility RWE. Carbon risks are modeled through varying carbon price paths and German national allocation rules. On that basis cash flows for large part of German RWE power plants are predicted. Besides, the replacement of existing plants is modeled by three replacement options: fuel by fuel, fuel by coal and fuel by gas. Ultimately, by means of the DCF model, the value impact of these replacement strategies and different carbon prices is calculated to derive the value at risk from carbon.

[49] See Société Génétale (2007): CREAMing carbon risks. European carbon winners and losers, Equity Research Report.

[50] See Carbon Trust / McKinsey (2008): Climate Change: A Business Revolution?, London 2008.

[51] See SAM and WWF (2006): Carbonizing Valuation. Assessing Corporate Value at Risk from Carbon, Zurich 2006.