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Thesis Title

"Electricity Prices, Storable Fuels, and Convenience Yields: An Inter-commodity Analysis in Futures Markets"

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Στους γονείς μου με αγάπη
Περίληψη

Οι τιμές ηλεκτρικής ενέργειας στην απελευθερωμένη αγορά εμφανίζουν εποχικότητα, απότομες αυξήσεις με την τάση επιστροφής σε ένα μακροχρόνιο μέσο όρο, αλλά και μεταβλητότητα κυρίως λόγω της αδυναμίας να αποθηκευθεί, αλλά και της ανελαστικής ζήτησης ως προς την τιμή. Η αδυναμία δημιουργίας αποθεμάτων για μελλοντική χρήση υποδεικνύει την ανάγκη η προσφορά ηλεκτρικής ενέργειας να προσαρμόζεται στο επίπεδο της ζήτησης. Στο πλαίσιο αυτό, η υπάρχουσα βιβλιογραφία σχετικά με την αποτίμηση προθεσμιακών συμβολαίων στο αγαθό τονίζει ότι η θεωρία της Αποθήκευσης δεν βρίσκει εφαρμογή, καθώς το υποκείμενο αγαθό δεν μπορεί να διατηρηθεί και να μεταφερθεί σε μια μελλοντική χρονική στιγμή. Λόγω της ιδιαιτερότητας αυτής, η σχετική βιβλιογραφία προσεγγίζει το θέμα με βάση τις αρχές της Κανονικής Οπισθοδρόμησης, σύμφωνα με την οποία η προθεσμιακή τιμή είναι μικρότερη από την προαναφερόμενη μελλοντική τιμή κατά το ασφαλιστρο κινδύνου το οποίο αποτελεί ένα είδος αποζημίωσης για τον κίνδυνο που αναλαμβάνει ο αγοραστής Συμβολαίων Μελλοντικής Εκπλήρωσης στην προθεσμιακή αγορά.

Ωστόσο, θεωρείται ότι η ηλεκτρική ενέργεια είναι έμμεσα αποθηκεύσιμη στα καύσιμα τα οποία χρησιμοποιούνται στην παραγωγική της διαδικασία. Αν και το πιο κοινό παράδειγμα αποτελεί η παραγωγή ενέργειας από υδροηλεκτρικούς σταθμούς, η υπόθεση αυτή θα μπορούσε να εφαρμοστεί και στην περίπτωση άλλων ενεργειακών πόρων, όπως ο γαιάνθρακας και το φυσικό αέριο τα οποία αφενός είναι αποθηκεύσιμα και αφετέρου χρησιμοποιούνται ευρύτατα στο μείγμα καυσίμων της βιομηχανίας ηλεκτρισμού. Λαμβάνοντας υπόψη τις παραδοχές αυτές, η μελέτη προτείνει ότι οι αρχές της θεωρίας της Αποθήκευσης θα μπορούσαν να έχουν εφαρμογή στην τιμολόγηση προθεσμιακών συμβολαίων ηλεκτρικής ενέργειας με στόχο να αποτυπώνεται η θεωρούμενη έμμεση αποθήκευση μεταξύ του τελικού αγαθού και της πρώτης ύλης που το παράγει. Προτείνεται ότι η βάση των τιμών ηλεκτρικής ενέργειας, δηλαδή η διαφορά μεταξύ της προθεσμιακής και της τιμής μετρητών επηρεάζεται από το διαχρονικό κόστος μεταφοράς του καυσίμου που χρησιμοποιείται στην παραγωγική δραστηριότητα. Πιο συγκεκριμένα, επηρεάζεται από το ύψος αποθεμάτων του καυσίμου το οποίο συνδέεται με την έννοια της απόδοσης ευκολίας λόγω της αντίστροφης σχέσης που συνδέει, βάσει της θεωρίας της Αποθήκευσης, τα δύο αυτά μεγέθη. Η πρόταση αυτή, η οποία σε εμπειρικό επίπεδο εξετάζεται με στοιχεία από την αγορά ενέργειας των ΗΠΑ, συνεισφέρει στην υπάρχουσα βιβλιογραφία, καθώς προσφέρει ενδείξεις ότι κύριες παραδοχές της θεωρίας της Αποθήκευσης μπορούν να αποτυπωθούν στην αποτίμηση προθεσμιακών συμβολαίων ηλεκτρικής ενέργειας.
Abstract

Prices in deregulated power markets exhibit seasonality, mean-reversion, price spikes and time-varying volatility, mainly due to the non-storable nature of electricity and the limited elasticity of demand in the absence of substitutes. The inability to store electric energy on the grid implies that potential shocks in the supply side—such as unexpected outages of power plants, are more common to occur. In this context, the existing literature suggests that the cost-of-carry theory is not applicable in the valuation of power derivatives contracts. For that purpose, the latter is approached by the assumptions of the normal backwardation theory. According to this view, the futures price reflects market participants’ expectations on the spot price at the date of delivery and the risk premium for the uncertainty that hedgers are willing to pay as insurance to unexpected price changes.

However, it is suggested that electricity is indirectly stored through the fuels incorporated in its power generation. Even though, the most common example of this presumption associates with the use of hydro in power generation, the rationale can be extended to other energy resources such as natural gas and coal, which represent an important part of power generation in the industry. Moreover, it is observed that volatility in spot and futures electricity prices increases during periods of lower storage inventory in the markets of energy resources.

According to the preceding arguments, this study incorporates the assumptions of the storage theory in the valuation of futures power contracts in order to propose a relationship that supports the indirect relationship between electricity and the fuel used in the generation process. We argue that changes in the basis, i.e., the difference between the futures and the contemporaneous spot electricity prices can be explained by the changes in the level of inventory in fossil fuel markets. For that purpose, the notion of the convenience yield is incorporated by taking into account the inverse relationship to the level of inventory proposed by the theory. The proposition, which is also empirically examined with data from the US energy markets, contributes to the existing literature by providing evidence that the implications of the storage theory can be applied in the pricing of electricity futures contracts.
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Introduction

The characteristics of deregulated electricity markets

Restructuring in the power sector has led to the unbundling of a vertically integrated industry and the introduction of commercial transactions across the functions of generation, distribution and transmission. Additionally, prices in deregulated power markets are subject to seasonality and temporary upward movements due to the non-storable nature of the commodity and its inelastic demand. As a result, the amount of electricity generated and transmitted in the network (supply-side) should be balanced to the amount of power demanded at all times.

In addition, deregulation of the energy industry has led to an increasing trading activity in the futures market, as power producers and retail firms are seeking to hedge their exposure to unexpected price changes. Over-the-counter forward agreements and futures contracts have been the most actively traded derivative instruments in the electricity exchange markets during the last decade.

As far as futures contracts are concerned, the most common approaches for their valuation are the theory of normal backwardation and the storage or cost-of-carry theory. Normal backwardation theory, which originated with Keynes (1930), proposes that speculators hold long positions in the futures market requiring a premium for the risk they undertake against the spot price exposure. Respectively, producers accept to sell futures contracts at lower prices in order to secure their production process against price changes in the future. For that purpose, the Keynesian view argues that the futures price is a downward biased estimate of the forthcoming spot price.

On the other hand, the theory of storage documented in the studies of Kaldor (1939), Working (1949) Brennan (1958) and Telser (1958), considers inventory as a major determinant of the futures price. The theory introduces the concept of convenience yield, which describes the unobserved return emerging from holding goods, in stocks rather than owning a derivative instrument. In this case, profits can arise when the commodity is in relative scarcity. For that purpose, the cost of carrying a storable commodity, which consists of the interest foregone and the outlay on physical storage must be reduced by the convenience yield. Moreover, by the time that buying (selling) in the spot and selling (buying) in the futures market is a riskless trade, the net cost of carrying the commodity until the date of the contract’s expiration should reflect the basis, i.e., the difference between the futures and the contemporaneous spot price.

A review of the literature on electricity markets indicates that valuation of futures contracts is mainly approached using the normal backwardation theory (Eydeland and Geman, 1998; Bessembinder and Lemmon, 2002; Lucia and Schwartz, 2002; Longstaff and Wang, 2004;
Pirrong and Jermakyan, 2008). Due to the non-storable nature of electricity, it is suggested that the cost-of-carry theory and the implied arbitrage arguments are not applicable. For that purpose, the futures electricity price is decomposed of the expected spot price at the delivery period and the risk premium for the uncertainty that market participants are willing to bear instead of selling at fixed prices. At a theoretical level, the most well-known proposition in the literature by Bessembinder and Lemmon suggests that the risk premium in a futures power market is negatively related to the variance of the wholesale price and positively related to its skewness. Empirical studies that employ data of spot and futures prices from various power exchange markets confirm the existence of statistically significant risk premia that exhibit high volatility and regular changes in sign (Longstaff and Wang, 2004; Furio and Meneu, 2010).

The scope of the dissertation is to investigate the proposition that in the power industry an indirect type of storage exists through the fuel(s) used in the generation process. The most common example is the generation of electricity by harnessing the power of moving water. Hydropower plants produce electricity after releasing water inflows, which have been previously stored in reservoirs. Based on that view, it is argued that the lack of storage in electricity markets is partially offset by the availability of energy resources, such as the fossil fuels used interchangeably in the power industry.

The impact of this indirect type of storage can be also inferred by the tendency of spot and futures power prices to undergo significant upward movements during periods of lower inventories in major energy resources employed in power generation. Thus, well functioning markets of fossil fuel reserves should be associated with an increasing level of security of supply in the electricity industry.

The objective of the study is to apply the preceding rationale in a proposition that incorporates the assumptions of the storage theory in the pricing of futures power contracts. We argue that deviations in the basis of electricity prices can be related to the carrying costs of major energy resources used in power generation. In particular, we are interested in showing the impact of fuels’ inventory on the distribution of electricity prices. We do so by employing the concept of convenience yield emerging from the spread between the spot and the futures prices of the fuel. The use of the convenience yield is critical in our proposition, since it is assumed to be inversely related to the level of inventory, according to the theory of storage. In this way it is considered as the appropriate proxy in order to introduce the principles of the storage theory in the pricing of power futures contracts and at the same time to examine the impact of fuel’s inventory on the distribution of electricity prices. To the best of our knowledge this is the first study that incorporates the implications of the cost-of-carry theory in the context of power derivatives pricing.
The proposed model and its implications

The study considers the relationship between the price of electricity and the fuel cost of “primary” energy resources used in the generation process. The term primary is used to underline that the market price in the power industry is closely related to the operating costs of the power plants dispatched by the system operator according to the level of demand. The relationship between the input commodity (the fuel) and the final good (electricity) is employed in order to introduce the implications of the storage theory. For that purpose, the assumptions of competitive wholesale electricity markets, the existence of futures power markets and of storable energy resources (fossil fuels) are essential.

In contrast to regulated power markets where tariffs reflected the average cost of production, in competitive electricity markets the sale price is determined by the level of supply and demand. Moreover, the rates charged to retail consumers exhibit small variation compared to the wholesale prices, which are subject to fluctuations on a daily or even hourly basis. Price volatility therefore, is an important feature in the proposed methodology, since it is related to the dispatch of power units by a system operator and subsequently to the differing marginal costs of generating facilities confronted with the level of demand.

In the literature, it is asserted that the generation of electricity from an integrated fuel mix adds complications in the examination of the relationship between electricity and fuel prices. We argue that the method with which prices in organised power markets are determined enables to concentrate on a specific type of fuel and subsequently examine the impact of it on the electricity price distribution. This is accomplished through the so called “merit order mechanism”, according to which the system operator ranks, in an ascending order, the price offers submitted by power units and dispatches those units with the lower bids that suffice to cover demand for electricity. As a consequence, a convex supply curve emerges, which becomes vertical when the capacity limit of the system is reached.

The spot price, known also as the market clearing price, is determined at the point where the inelastic demand intersects with the supply curve. In addition, the market clearing price is uniform implying that the units dispatched by the system operator to offer power in the grid receive the same fee, which is determined by the plant that submits the highest accepted offer. This type of price allocation is considered to assign the principles of competitive electricity markets, in which the wholesale price reflects the marginal cost of production among all efficiently allocated resources.

According to that rule, base load units are found at the top of the merit order because they use less expensive fuels in order to produce electricity at a steady state throughout the year. In contrast, intermediate and peak load units, which provide power when demand is higher, are allocated further down at the order with which they are dispatched. Therefore, as demand for electricity increases the wholesale price becomes more expensive, indicating the
fuel switch to power units with higher operating costs. In either case, certain types of plants
determine the market-clearing price at a given point of time. The term “marginal fuel” is
employed in the study to describe the energy resource that submits the highest accepted
offer and subsequently determines the spot electricity price at a given time. This presumption
offers also the opportunity to empirically examine the differences in the distribution between
off-peak and peak electricity prices.

Moreover, we assume that a futures power market exists in which financial contracts are
traded for delivery of the commodity at a future date and at a specified price. Power
producers with long positions in the spot market can hedge from unexpected price downturns
by selling contracts of specific volume (amount of MWh) in the futures market. Respectively,
power retail firms that serve as intermediaries between power industries and end consumers
run the risk of exposing their business to significant losses in case the wholesale price
increases considerably, since they (usually) sell power at fixed rates. In order to mitigate
price uncertainty they can enter the futures power market, buy futures contracts — obtain
therefore a long position in the futures market, and hedge against that likelihood.

In addition, given that the fuel markets and the power industry are interrelated, a conversion
process exists that incorporates the process of transforming a certain type of energy into
electricity. A theoretical proposition is derived based on the conversion process, which
incorporates the properties of the storage theory applied to the fuel used to set the wholesale
electricity prices.

In particular, the basis of electricity prices is modelled as a function of the fuel’s carrying
charges. Assuming two periods (time t be the present and a future date T) the difference
between the futures and the contemporaneous spot electricity prices is linearly related to the
marginal fuel’s cost of storage and its convenience yield. The proposed relationship is
expressed as:

$$Basis_{Electricity}^t = c + b \times HR \left[ S_{t}^{Marginal\ Fuel} - Z_{t,T}^{Marginal\ Fuel} - S_{t}^{Marginal\ Fuel} - S_{t}^{Marginal\ Fuel} \right]$$

where $S_{t}^{Marginal\ Fuel}$ is the marginal’s fuel compounded price at date t, $S_{t}^{Marginal\ Fuel}$ denotes the
cost of storing the commodity from time t to T, while $Z_{t,T}^{Marginal\ Fuel}$ is the convenience yield for
the same period of time. The parameter (c) denotes the transmission costs of electricity,
which are assumed constant.

This expression is assumed to depict the impact of the fuel’s demand for storage on power
prices given that electricity cannot be economically stored in significant quantities. The
demand for storage is closely related to the demand and supply conditions in the fuel
markets. Following a change in supply or demand the level of fuel inventory should change as
well, implying that fuel purchases and inventory policies are essential decisions in a power
units’ operation. For instance, low inventory in fossil fuel markets may be associated with
supply shortages, mainly during periods of unexpected weather conditions. This case illustrates the role of storage in mitigating price volatility in the entire energy market through the ability of the market to respond to sudden demand or supply changes.

It should be underlined at this point that the study assumes that imports of electricity are implicitly included in the merit order dispatch. In this way they are conceived as part of the domestic production, such as the amount of power provided by the units in the local (or regional) market. This assumption which is met in the literature of electricity markets can be considered robust if we take into consideration that power markets remain, to a large extent, self-sufficient due to congestion issues and the need to avoid potential interruptions related to increasing levels of import dependency. For this purpose, we empirically test our proposition with historical data from markets that exhibit regional characteristics. In this way, it is expected that the effect of imports (and exports as well) will be weaker relatively to other power markets with significant cross-border energy trading.

According to the proposition, the basis in electricity market should be negatively related to the marginal fuel's convenience yield, implying that in case the level of supply and inventory in the fuel market are adequate to meet demand, then an increase in the commodity’s spot price is less likely to occur. Likewise electricity prices are expected to be lower, since the fuel cost is the major component in electricity prices.

On the other hand, shortages in fuel inventory should lead to higher prices and convenience yields as well. In the case of electricity, it means that power generators will have to carry the burden of increased fuel costs, leading in turn to higher wholesale power prices. In terms of the proposed relationship, a negative basis in electricity or lower futures prices compared to concurrent spot prices may be observed, as reserves in the fuel markets diminish.

In the existing literature, the impact of the fuel's supply has been mainly incorporated in the case of hydro power plants in which case, the behavior of spot and futures electricity prices is examined in relation to the level of water reserves. Other studies, review the term structure of electricity futures prices according to the properties of the underlying asset (usually the spot price) such as its stochastic volatility, price jumps and the property of mean reversion. However, these studies do not take into consideration the potential impact in power prices of fuel inventory.

This view is only depicted in the study of Douglas and Popova (2008), in which the amount of natural gas in storage is considered among the determinants of the risk premium in futures electricity markets. Unlike Douglas and Popova, though, this dissertation employs the concept of convenience yield to address the impact of fuels’ storage, albeit indirect, in power prices. According to this view and given that futures power contracts are used as hedging instruments, variation in the basis of electricity prices can be explained by the changes recorded in reserve levels of any storable energy resource used in power generation.
The theoretical proposition is evaluated with empirical data from US energy markets by taking into consideration that the difference between the convenience yield $Z_{t,T}^\text{Marginal Fuel}$ and the cost of storing the commodity $SC_{t,T}^\text{Marginal Fuel}$ represents the net of storage convenience yield (i.e., $Z_{t,T}^\text{Marginal Fuel} - SC_{t,T}^\text{Marginal Fuel}$) and by using proxies for changes in demand for power due to weather conditions. The regression is of the form:

$$\text{Basis}_{t,\text{Electricity}} = \beta_0 + \beta_1 S_t^\text{Marginal Fuel} \times r_t + \beta_2 NZ_{t,T}^\text{Marginal Fuel} + \beta_3 \text{HDD}_t + \beta_4 \text{CDD}_t + \epsilon_t$$

where $\beta_i = 0, 1, \ldots, 4$ are the coefficients to be estimated using the OLS method, $NZ_{t,T}^\text{Marginal Fuel}$ represents the net of storage convenience yield, while the Heating Degree Days (HDD) and Cooling Degree Days (CDD) are relative measures with respect to a standard level of temperature. They are calculated from historical data of temperatures collected from meteorological stations in order to provide an indication of variation in demand for heating and cooling respectively.

We assume that natural gas is the marginal fuel during the hours of higher demand for electricity and coal during the off-peak hours respectively. We used data for power markets in the USA. For the peak demand case, data from the PJM Interconnection and the Palo Verde trading hub were employed, whereas for the off-peak case electricity prices from the Mid-Columbia market were used. These power markets are among the most developed trading points of electricity globally.

As far as the fuel markets are concerned, we used natural gas spot and futures prices from the Henry Hub Louisiana market, while coal prices were obtained from the Central Appalachia coal region. In both markets large trading volumes are recorder every year and for that reason they are considered robust representatives of these energy resources. Moreover, futures contracts of these commodities are traded in the New York Mercantile Exchange market.

By employing data of futures contracts for one, three, six and twelve months to maturity, the econometric tests verify the main assumption of the dissertation, i.e., that there is a negative relationship between the basis of electricity and the convenience yield of the marginal fuel. Either in the case of PJM and Palo Verde markets where natural gas prices have been incorporated or the Mid-Columbia power market in which coal power units provide a large proportion of total power produced, OLS estimates for the (net of storage) convenience yield are negative and statistically significant for most of the contract maturities assumed. These findings are also supported by the fact that the inverse relationship between inventory and convenience yield proposed by the cost of carry theory is confirmed in the case of Henry hub natural gas and Appalachia coal markets as well.
As a final remark, a potential critique on the analysis relates to the likelihood of missing variables from the weak explanatory power of the model. It is important to note, however, that our goal is to test the applicability of the theory of storage to electricity, as opposed to building a model that can explain or predict the basis. The nature of electricity is indeed such that storage theory could not explain the price relationships in all their complexity, yet our results indicate that it can provide considerable insight, which has been overlooked so far in the literature. As long as there is no missing variable correlated with both the basis and the convenience yield, which would bias our estimates, the outcome of our analysis holds. Still, it should be made clear that the availability of complete and reliable data is a serious obstacle.
Chapter 1: The main features of the power market

1.1 Introduction

Electricity is a form of energy used for applications such as heat, light and power. It is considered a secondary source of energy since it results from the conversion of other energy resources such as natural gas, coal, nuclear power, hydro power, wind and other renewable resources. Electricity market has been grown proportionally relatively to other energy markets. In the early 1970s power consumption accounted for the 11% of the total energy consumption, whereas during the last decade it has increased to approximately 20%. Likewise, it is expected to rise at the rate of 2.5% to 3% in the future, with an even higher growth rate in the non-OECD countries.

On the other hand, significant restructure has taken place in the power sector across the world, mainly associated with the divestment of a vertically integrated industry and the introduction of commercial activities between the functions of generation, distribution and transmission. The New Zealand electricity market was the first fully deregulated power market in the world, although the introduction of privatisation in the sector occurred in Chile in the early 1980s, followed by the United Kingdom. The primary objective of the reform was the improvement of the sector’s economic efficiency and the provision of better consumer services.

Competition in the power industry, both in production and trade encounters a different kind of disadvantages. Even though in practice, the market is not differentiated relatively to others, since the commodity's price is determined by demand and supply, the major technical issue characterizes the commodity is the inability to store and release power from inventory. This means that power must be generated and withdrawn according to the level of demand. Moreover, the amount of power transmitted in the grid\(^1\) is restricted, implying that the failure of generation to meet demand will result in short or long-term losses of electric power, known as power outages or blackouts. Finally, inelastic demand for electricity adds considerable complexity, making the effective operation of the market a difficult task to be managed.

1.2 The electricity supply chain

Electricity delivered for end use is a bundle of services. The main components are power generation, high-voltage transmission and low-voltage distribution. In a regulated environment the network was combined in a single firm with functional separations in

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\(^1\) An electric grid is a network of synchronized power providers and consumers that are connected by transmission and distribution lines and operated by one or more control centres. When most people talk about the power “grid,” they’re referring to the transmission system for electricity.
different administrative divisions. Unbundling of the electricity sector on the other hand, has taken place mainly in the generation and the distribution parts of the supply chain. In contrast, the transmission system has remained under the state control in many countries due to the large investments required.

**Figure 1.1: The electricity supply chain**

Competition in power generation has become viable because new types of high-efficiency power plants have been developed that produce electricity with lower capital costs than traditional power plants. A wide variety of technologies and primary energy sources are used to generate electricity. Non-renewable sources include coal, natural gas, oil and uranium, while renewable sources include hydro, wind, solar, geothermal power and biomass.

**Figure 1.2: World electricity generation by fuel, 2006-2030**

Coal is a combustible rock consisting of more than 50 per cent of weight and more than 70 percent of volume of carbonaceous materials. It is found naturally underground and is
extracted via mining. In addition to carbon, coal contains other particulates (for example nitrogen, sulphur etc.) as well that result in pollutant emissions when coal is combusted in the power generation process.

Oil is a liquid fossil fuel that is composed of decayed organic matter that occurs naturally in underground reservoirs. It is extracted from subsurface reservoirs as crude oil and is sent to refineries for separation into its various component fuels, such as kerosene, diesel and aviation fuels. The use of oil in power stations is small and decreasing as well, since it is expensive compared with other energy resources.

Respectively, natural gas is a mixture of hydrocarbons, primarily methane. Other gases typically include ethane, propane, nitrogen, water vapor, and carbon dioxide. Natural gas is extracted from reservoirs or gas streams, or can be separated from crude oil during the refining process. It is used as fuel in the form of gas, but it can be compressed also in liquefied form (Liquified Natural Gas) for transportation over long distances. The most common way of transmission is through pipelines, which are used in the transportation, industrial, commercial and residential sectors. The share of natural gas in power generation has risen substantially during the last decade, counted up to almost 20% of total electricity produced.

On the other hand, nuclear power accounts for the 12% of electricity generation. Canada, Australia, USA, Russia, Ukraine, Uzbekistan and South Africa are the main sources of the specific energy resource. Even though, it is considered a clean type of energy since there are any greenhouse gas emissions, nuclear power faces the unresolved waste disposal of uranium and the risk associated with potential accidents similar to the Fukushima nuclear plant in March 2011.

Figure 1.3: A pumped storage facility
Alternatively, the use of water (rivers, lakes, waves and tides), wind and sun (photovoltaic) has become a major issue in power generation, with renewable energy promoted as a means to reduce gas emissions. Wind and solar energy have gained popularity during the last two decades, in contrast to hydropower which is among the oldest methods of producing electricity accounting for approximately 16% of global supply. The importance of renewable resources in power generation is depicted, among others, in the European Union’s energy policy, according to which 20% of the EU’s final consumption should be met by renewables in 2020.

In addition, hydropower generation represents the most common example of an indirect type of storage in the literature of electricity markets. Pumped hydro storage uses electricity generated during periods of low demand to inflate water from a lower level (for instance a lake) to a higher elevation reservoir. When demand for electricity increases, the water is released to flow back to the lower reservoir, while turning turbines to generate electricity, as conventional hydropower plants do (Figure 1.3). In this kind of technology therefore, hydro resources come from controlled inflows of water rather than from exogenous inflows.

### 1.3 Demand for electricity and power generation

The main determinants of demand for electricity are weather and economic activity. For instance, demand is higher during summer and winter, when air-conditioning and heating needs increase or during the working hours and weekdays relatively to weekends. Furthermore, demand for electricity is inelastic, implying small responsiveness of prices as demand changes.

**Figure 1.4: Daily demand variations for electricity in winter and summer season**

Inelastic demand for electricity is attributed to the lack of real time metering in the power sector, which means that users are aware of the amount of power they have consumed and its cost only after consumption has taken place. For that reason, customers cannot respond
to high prices by reducing their consumption. Moreover, low responsiveness of demand is driven by the lack of substitutes. Normally, demand for electricity follows a bell shaped curve, with peaks changing according to the season (Figure 1.4). Even though, during the early morning and late evening demand is lower, it is never below a certain point. Demand is also affected by conditions such as the geographic location, population and climate conditions. For instance, it is higher in regions with cold weather compared to a place with mild climate or in industrial areas relatively to sparsely populated regions.

Electricity demand therefore, is heterogeneous and in order to be constantly balanced with supply, a single kind of power cannot effectively serve it. For that reason, a mix of fuels in generation is required that varies according to the level of demand. This is distinguished between base load, intermediate and peak load power plants. Base load units produce power at a constant rate, with demand shifts supplied by intermediate and peak load power plants. Usually base load plants require more time to start up, while they operate throughout the year, except in times of repairs or scheduled maintenance. The preceding characteristic implies that the cost of producing electricity should be as moderate as possible and due to that reason coal is usually used as a low cost energy resource. In some regions, geothermal or hydro power (the case of Scandinavia with abundant water supplies) is also employed in base load power generation.

The gap between base and peak demand is bridged by intermediate load plants. In addition, intermediate and peak power plants are coordinated so that changing demand for power can be met. Peak load power plants can be set in operation relatively quickly, thus adjustments in the amount of electrical output can take place on a short notice. However, despite the fact that they require less construction investments, they are more expensive to operate relatively to the amount of power they produce due to higher operational (fuel) costs. According to data from IEA, the average cost of natural gas used in electricity generation in the US was 3.6 times as expensive as coal during the period 2002-2011.

1.4 High Voltage transmission and distribution

Transmission is the link between generation and consumption, incorporating the bulk movement of electricity at high voltages (400kV) from power plants to distribution companies. The responsibility for the bulk transmission belongs to the Transmission System Operators (TSO). High voltage transmitters (or the grid) deliver power over very long distances, instantaneously and with small delivery cost. In high-voltage transmission systems, the lines are usually composed of wires of copper, aluminium or steel, which are suspended from tall latticework towers of steel. In this way the distance between towers can be increased and subsequently the cost of transmission is reduced. However, the network of circuits is constrained by thermal, stability and security limits. Given a finite resistance in the wires, the heat cannot surpass a certain limit; otherwise damages will occur.
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Distribution on the other hand, refers to the provision of electricity to the majority of customers through lower voltage networks (from 132kV to 230V). After electricity is generated and transmitted, step-down transformers located in distribution substations reduce the voltage so it can be carried on smaller cables or distribution lines before delivered to consumers. The distribution system includes substations, wires, poles, billing and relevant support systems involved in the retail side of electricity delivery.

1.5 Interconnections

An Interconnection is a transmission link between two control areas. It involves the transmission of electricity across many regions and it is associated with significant benefits; the most important is the ability to trade electricity with neighbouring regions or countries. The latter occurs, when surplus generation capacity in a region covers shortfalls in another location, reducing in this way the need for spare capacity across the whole network.

During the last decades, the need to supplement the supply of electricity led to the development of regional electricity markets. This approach allows each country to reduce its capacity margin requirements. The reduction leads to significant savings as far as investment and operating cost among the districts interconnected is concerned. Interconnections can increase the security margin of a system through the production and consumption patterns of the neighbouring systems.

Interconnected electricity generators through the transmission system, enables the use of less expensive generation irrespective of location. From the supply’s security perspective, interconnections provide the customer with continuous and uninterrupted power even if a power unit or parts of transmission and distribution networks have failed. In Europe Interconnections between power networks have been developed from the early 20th century. Currently there are four synchronously connected high-voltage transmission systems within the EU, i.e., the Continental, the Scandinavian, the British and the Irish.

The European Network for Transmission System Operators for Electricity (ENTSO-E), formed in mid 2009, aims to strengthen cross-border energy collaboration and investments in electricity markets within the European Union. ENTSO-E that took over the operational tasks from six pre-existent associations represents the body of 42 TSOs. The objective is to develop the common commercial and security standards and to coordinate the capital investment project at an EU level. By doing this ENTSO-E aims to promote the reliable operation and optimal management of the European electricity transmission system so as to ensure the security of supply and to meet the needs of the internal energy market.
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Figure 1.5: European countries participating in the ENTSO-E

In the USA, the Federal Energy Regulatory Commission (FERC) has encouraged the formation of Regional Transmission Organizations, which are in charge of administering the transmission grid on a regional basis within the States of North America, included Canada. In order for an entity to become Regional Transmission Organization, specific characteristics and functions should be satisfied.

Figure 1.6: Regional Transmission Organizations in North America

Among the most well functioning electricity markets worldwide, is the Pennsylvania-Jersey-Maryland (PJM) Interconnection, which is a regional transmission organization that coordinates the movement of wholesale electricity and manages the high-voltage electric grid in 13 States of the US and the District of Columbia.
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1.6 Electricity trading

Electrical trading refers to the amount of power delivered at a specific period of time, typically set in an hourly basis. Taking into consideration that supply must be constantly matched with demand, production facilities are in place to ensure certain adjustments. However, the number of plant output decreases or increases within the day according to the level of demand. Subsequently, the market clearing price does not remain stable by the time that each power unit faces different operating costs. Those kinds of fluctuations in the production cost as well as the wholesale price of electricity are not usually met in other commodity markets. Due to the discrete market structure of the power industry, the most common types of trading that have been developed are bilateral contracts and pool markets.

Bilateral trading is a simple form of trading involving no third parties but the buyer and the seller of electricity. A common type is the sale of significant amounts of power through contract agreements over a long period of time. These contracts are flexible since they aim to meet the needs and objectives of both parties. There is also the so called “over the counter” (OTC) trading that involves transactions of smaller amounts of energy, usually during different periods of the day or the week. In this form of bilateral trading transaction costs are lower, offering both parties the opportunity to refine their positions as the delivery time of electricity approaches.

In contrast, pool markets are centralized forms of trading electricity. Instead of relying on interactions between suppliers and consumers to reach the market equilibrium, pool markets provide the mechanism for determining this balance. Even though variations can exist, power producers in a pool operation submit offers indicating the amount of electricity they are able to produce at a given price.

Likewise, the demand for electricity has distinctive differences compared to other commodities where the demand curve reflects offers between quantity and price with each pair ranked in a decreasing order of price. The demand function is therefore downward sloping, indicating that the amount consumed declines as the price increases. In the case of electricity, however, demand shows significant variation, even on an hourly basis. Given that demand should not exceed supply in order to prevent system blackouts short term forecasts are required for dispatching electric energy. For that purpose, the shape of the demand curve in the power industry is represented by a vertical line, at the point of the load forecast.

The intersection of demand and supply curves determines the market equilibrium. All the bids ranked at a price lower than or equal to the equilibrium price are accepted and generators are instructed to produce the amount of energy corresponding to their offer. The market clearing price represents the price required in order an additional MWh of energy is generated. For this type of trading, the market operator is responsible not only for the collection of the bids, but also for the determination of the dispatch and the functioning of
other auxiliary services. In deregulated electricity markets those duties come under the jurisdiction of the Independent System Operator (ISO).

It should be underlined that in the absence of transaction costs, pool and bilateral trading should be equivalent. However, in bilateral trading prices and quantity do not reflect real time conditions in the market. In some occasions nevertheless, market participants enter the bilateral market in tandem with the pool market. In this case, power units supply the amount of load specified, while the pool is responsible for the clearing of possible price differentials emerging from differences between the amount of energy scheduled and the amount observed in the real time operation.

On the other hand, the non-storable nature of electricity is associated with higher fluctuations in prices. The need of proper risk management in the power industry has led to the introduction of futures contracts and other derivative products, soon after the restructuring of the sector has taken place. In the futures market, electricity contracts are traded in organized exchanges with hedging against price volatility in the cash market being the primary purpose of firms or individuals who enter the futures market.

Another type of trading electricity for future delivery is forward contracts. These are standardized instruments traded on a monthly or a seasonal basis for different hour blocks. The contract specifies the quantity of MW and the price per MWh as well. The seller of the forward contract undertakes the obligation to deliver electricity at a constant rate and specified location, known also as the hub. Upon delivery, the buyer of the forward contract uses electricity in order to deliver power from the hub to the load location. In cases of shortages or surpluses in the amount of electricity produced, purchases or sales respectively of power from the spot market can take place respectively. However, those transactions are not part of the contract and subsequently they have no effect in the price of the forward contract. Futures contracts differ from forward contracts to the extent that they are traded in organized exchanges rather than in OTC transactions.

Organized exchange markets for electricity trading have been developed in many countries, mostly in Western Europe. Among the first established power exchanges was the Nordpool. The market has a long experience as futures contracts have been traded since 1995. The Nordic electricity system and the transmission network are owned and operated by a number of independent TSOs. It is formed by Norway, Sweden Finland and the western part of Denmark. The NordPool Exchange is organized in two markets the physical market (Elspot) and the financial market (Eltermin and Eloption).

Elspot is a spot market in which day-ahead electricity power contracts are traded for physical delivery for each one of the 24 hours of the following day. The system price is fixed for each hour in the following day based on the balance between aggregate supply and demand. Respectively, Eltermin allows trading in financial contracts, such as forward and futures with
delivery periods up to 3 years in advance. Since September 1995, none of those contracts entails physical delivery. They are settled in cash against the system price in the spot market. They refer to a base load of 1 MWh during every hour for a delivery period of one week, one block (4 weeks), one season and one year.

Figure 1.7: European Power exchange markets

The European Energy Exchange (EEX) AG on the other hand, is the leading energy exchange in continental Europe for trading of power, natural gas, emission rights and coal, contributing also to the integration of the European electricity markets. It was founded in 2002 through the merger of the Leipzig and the Frankfurt power exchanges. EEX is a 50 per cent shareholder of EPEX Spot SE, established in the context of the co-ordination between EEX and Powernext, the spot market for Germany, France, Austria and Switzerland. EPEX Spot holds hourly auctions on a day-ahead basis for the whole week. The Physical Electricity Index (Phelix) daily average price –Phelix Day Base and Phelix Day Peak–, which is based on the power auctions of EPEX, is considered the reference price for wholesale electricity in Germany and other parts in Europe.

In Spain, deregulation led to the implementation of a competitive wholesale electricity market. The management of the new market was assigned in two distinctive entities, namely the Market Operator (OMEL) and the system operator. The electricity market is organized between a daily market that negotiates electricity for delivery on a day-ahead basis and an intraday market, which is in charge of possible modifications in demand and supply commitments. OTC bilateral trading is also permitted but it has to be communicated to the system operator.

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2 As of December 2009, nineteen European countries, Greece among them, and 191 trading participants are active on EEX.
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In Portugal the market operator (OMIP) has introduced the trading of futures base load contracts, for cash settlement and physical delivery, with weekly, monthly, quarterly and yearly maturity. The integration of electricity markets in Spain and Portugal led to the establishment of the Iberian electricity market that involved the merger of the market operators of the two countries into a single one (MIBEL).

The trade of electricity in deregulated markets can be described by Figure 1.8. Besides the organization of exchange and OTC markets, the non-storable nature of electricity implies the necessity of reserve markets.

**Figure 1.8: Trading activities in a deregulated electricity market**

Reserve markets contribute to an effective balancing management. Any imbalance between supply and demand causes the deviation of the system from its normal function. When the amount of energy produced exceeds consumption, the frequency (i.e. the speed at which electricity flows) in the transmission network rises, implying that energy should be withdrawn from the system in order for the frequency to be re-established at its set-point value. Withdrawn of energy is usually made through pumped storage facilities, which use excess power to elevate water from the lower reservoir (see Figure 1.3). In contrast, if consumption exceeds supply, the system’s frequency decreases and the transmission network should be fed-in with additional power. Due to the lack of electricity inventories a number of power units operate at less capacity in order reserve power to be readily available.

1.7 Monopoly and competitive equilibrium

The electricity industry is a vertically integrated market structure, characterized in the past by conditions of natural monopoly. Natural monopolies arise when a single firm has the ability to supply a market with a good or a service at a lower cost relatively to a larger number of firms. This is due to the economies of scale achieved from the company’s larger (or efficient) size, despite the significant capital costs entailed for its foundation. The argument behind the support for regulation in markets, such as the electricity industry, was that economies of scale cannot be achieved if a divestment of the natural monopoly in smaller firms takes place.
Subsequently, lower average cost would not be accomplished as well, leading in this way to increased prices for end users. In regulated markets, the pricing policy was under the public utilities’ control and for that reason price patterns showed little variation.

Being the only participant in the market, a monopoly is “price maker”, which means that it can also determine the output produced and the sale price as well. A monopoly faces a downward-sloping market demand curve\(^3\) that determines the price at which output is sold, once the profit-maximizing quantity is established (Figure 3.1). A profit-maximizing behavior is based on the decision rule that supplementary units of a good should be produced, as long as the marginal revenue of an additional unit exceeds the marginal cost. The profit-maximizing quantity occurs when the marginal revenue is equal to the marginal cost. In the graphical representation (Figure 3.1), the monopoly firm maximizes its profit by producing output \(Q\) at point A where the marginal revenue and the marginal cost curves intersect. The price, in which the production is sold is found by the price-quantity combination of the demand curve corresponding to the specific level of output (point B). According to the preceding rationale, it is evident that in monopolistic market the price is higher than the marginal cost (\(P > MC\)) at the profit maximizing level of output. Additional units can only be sold by lowering the price of the commodity.

\[\text{Figure 1.9: Cost and price characteristics of a monopoly}\]

\[\text{Area of Profit}\]

The difference between price and average total cost establishes the profit of the monopoly firm per unit of output. By considering the average total cost (ATC\(^*\)) at the output of \(Q\) units,

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\(^3\) A supply curve illustrates the quantity that a firm chooses to supply at a given price. Since, a monopoly firm is a "price maker", the firm sets the price and at the same time it chooses the quantity to supply, hence the demand curve indicates the level of supply by the monopolist.
the profit per unit should be given by the difference \( P - ATC^* \). Consequently, the total profit is found by multiplying the firm’s output, \( Q \) by the profit per unit, i.e., \( Q^* (P - ATC^*) \), which is given by the shaded rectangle area.

In contrast to a monopoly, a competitive firm takes the market price as given and determines its profit-maximizing output. The economic concept of a perfectly competitive market is based on the assumptions that:

a) The output of each seller and the consumption of each buyer is a small fraction of the market’s total output, hence their influence has a very small impact on the market price and quantity,

b) Consumers have perfect foresight, hence they can distinguish between different goods.

c) Resources flow from one market or sector of the economy to another

d) No externalities are assumed, meaning that the parties who contract over the supply of a good (or service) bear all the costs and benefits, associated with the production of the specific good (or service) and finally,

e) Products are not differentiated, implying that the division of the market into smaller parts is not possible.

The principal result of perfect competition is that firms earn zero economic profits in the long run. This can be mainly explained on the grounds of assumption (c). As long as firms are profitable additional enterprises will enter the market until a point where the increase in supply leads the price at a level that compensates only for the cost of production, the opportunity cost of capital and the managerial skill. Contrariwise, if negative profits are recorded, firms will exit the market until economic profits return to zero. Even though, economic profits tend to zero in the long run, perfect competition suggests that firms can gain profits in the short-run period.

**Figure 1.10: Perfect competition, the case of positive profit**

![Perfect competition diagram](image-url)
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In a competitive environment, each firm faces an infinitely elastic demand curve. Since elasticity of demand measures the responsiveness of the quantity demanded to the changes in the price, zero elasticity implies that price changes have no effect on the quantity demanded. Consequently, the firm can produce as much as it is able and sell at the equilibrium price without the increase in the quantity supplied having an effect on the market price, i.e., the firm acts as a “price taker”. In case a firm sells at price higher than the competitive level consumers will buy from another firm at the lower market price. If on the other hand, the firm sets its price below the competitive level it will sell the same amount as it would have done at the competitive price, but will end up with less revenue because of the lower selling price.

Figure 1.11: Perfect competition model – the case of negative profit

In perfect competition, revenues from selling additional units (the marginal revenue) are equal to the market price and due to that reason the firm’s demand curve, which is a horizontal line at the market price, is the marginal revenue curve as well. Moreover, the price-cost relationship determines the sustainability of the firm. If the price of the product is higher than the average total cost (constant and variable) for the amount of the commodity sold, the firm earns profit. The optimal quantity produced (point Q* in Figure 3.2) is determined at the intersection of the price and the marginal cost of production. At that point, average total cost is below the demand curve and costs are less than revenue, thus an economic profit (as that in the shaded rectangle) emerges.

Nevertheless, if the price is lower than the average total cost but higher than the average variable cost, the firm is unable to cover its constant cost and makes negative profit. In case the firm is able to cover its variable cost, then in the short-run period it would be in its interest to continue operating, even though in the long run its sustainability is uncertain.
Additionally, if the price is lower than the average variable cost, the firm has no incentive to run the business even in the short run period. The firm will reduce negative profits by cutting off its sales and paying only the constant cost. Figure 3.3 illustrates the case of economic loss where the firm produces up to the point where the marginal cost is equal to the marginal revenue; however, at that point of production the average total cost lies above the demand curve, which means that revenues are lower than costs.
Chapter 2: Literature survey

2.1 Introduction

In this chapter the main studies in the literature of electricity markets and the pricing of power futures contracts are reviewed. Research has been conducted in various segments of the market; the major part, however, concerns the behavior of electricity prices due to the commodity’s distinctive characteristics. For that purpose, statistical and mathematical models have been proposed, employing time series techniques in order to capture the particular features. Moreover, by the time power derivatives have been introduced in the energy exchange markets, their characteristics are also examined. Theoretical arguments propose that by the time electricity is non storable, the cost of carry theory is inapplicable, thus alternative approaches should be followed. Due to that reason, equilibrium models have been suggested that take into consideration the demand and supply of power.

2.2 The restructuring of electricity markets

Even though, the deregulation of electricity markets has taken place in many countries during the last two decades, most of the studies examine the effect of the reform in the power markets of United States and the United Kingdom. In the UK, the electricity supply sector remained under the public control of the Central Electricity Generation Board (CEGB) in England and Wales until 1990. The restructure of the CEGB, led to the emergence of a power pool and the utility’s division in four companies, three of which were sold to the public. The privatized companies were NationalPower and PowerGen that undertook the power generation from thermal plants and the NationalGrid, which was assigned the control of the high voltage transmission.

According to Newbery and Titman (1997), among the consequences of privatization was the improvement in labor productivity (GWhr/person/year) at a level higher than the UK’s industrial average. Moreover, it led to the rearrangement of the fuel plant mix, since the program of building new nuclear power plants was abandoned and generation from natural gas substituted the use of coal. In the first six years that followed deregulation, gas accounted for 23% of total generation compared to 1% in 1990, whereas purchases of British coal fell by approximately 40 million metric tones. In addition, the authors detect an improvement in the operating efficiency of the new companies, despite the high restructuring costs entailed by the reform. Moreover, changes in the pricing policy were beneficial for Electricity de France (EdF), the French nuclear energy utility, that provide electricity to the British grid. Before deregulation, the price paid to EdF reflected the average marginal costs set by the system operators of UK and France. After deregulation, EdF receives the pool price, i.e., the price emerging from demand and supply for electricity, which is usually higher than the preceding pricing rule.
Barnett, Isaacs and Thompson (1997) examine the effect of competition in US wholesale and retail electricity markets. They argue that competitive power markets can be beneficial to consumers in case power transmission takes place from the states with a surplus of power generation to those with deficits in supply. In particular, producers in regions with power surplus can increase their revenues by selling power to those regions with power deficit. In this case, retail prices in the exporting regions should rise because less generated electricity will be available to cover local demand. In contrast, power imports in markets with insufficient supply, will lead to the increase of electricity consumption and the decline of retail prices as well, since the imported power will be less expensive relatively to the power produced by local power units at peak demand.

Douglas (2006) investigates the efficiency of power plants coordination in US regional power markets after 1997. He focuses on the wholesale market, in which the ISO’s decisions have a primary effect on the market operation. Those decisions are reflected in the capacity factor (i.e., the rate of utilization) of power plants, which is given by the relationship:

\[
\text{Plant’s Capacity factor (in MW)} = \frac{\text{Electricity generated}}{\text{Total capacity}}
\]  

(2.1)

Douglas measures the cost sensitivity of dispatch by regressing yearly capacity factors on operating costs data. Results indicate an inverse relationship, which implies that power plants with increasing operating costs will be dispatched during the hours of higher demand, according to the merit order principle. In this way the amount of power generated by those power units will be lower.

Other studies, underscore the complication associated with deregulating electricity markets. Joskow (2003) argues that in some US regions, competition initiatives did not fully take into account the technical and institutional challenges needed for a successful introduction of competition in the wholesale and retail power markets. A similar argument is proposed by Trebilcock and Hrab (2005) for the Ontario electricity market, in which capacity shortages were attributed to the insufficient level of investments, the transmission constraints and the prolonged outage of nuclear plants mainly due to the uncertainty that governed the rules of the restructured market.

On the other hand, extensive research has focused on the California electricity crisis. According to Borenstein (2001), deregulation of electricity market was mainly driven by the higher prices observed in California relative to the nation’s average rates. Those higher prices were attributed to the costs (stranded costs) that utilities had incurred, due to large scale investments, such as the construction of nuclear power plants. During the summer of 2000, the Californian power market witnessed significant price fluctuations accompanied by capacity shortages within certain hours of the day. The regulatory constraints that prevailed, led the
three investor owned utilities, namely the Pacific Gas and Electric, the San Diego Gas and the Electric Southern California Edison to experience large losses.

The rules adopted when the market was initially designed had in reality eliminated from these utilities the ability to hedge against price volatility. This happened because the utilities were not allowed to enter in long term contracts for purchase of electricity in the wholesale market, while in addition retail rates were relatively fixed. As prices began to soar, utilities found themselves unable to pass any wholesale price increase to consumers. As a consequence, upward movements in natural gas prices combined with the drought the region suffered during the summer period drove the wholesale prices to a level well above than normal, leading in this way California’s largest utility, Pacific Gas and Electric, in bankruptcy and the other two companies to accumulate huge debts.

Borenstein, Bushnell and Wolak (2002) provide evidence that tripled wholesale expenditures in 2000 compared to one year earlier, was the result of power exercise in the electricity market of California. Firms able to exercise market power can reduce production or raise prices for the amount of power generated, leading in this way to the replacement of their production from other more expensive generation units. Borenstein et al. define market power as the difference between the price of electricity and the marginal cost of the units dispatched to supply the grid during the peak hours. Excluding transmission and congestion costs, they simulate the marginal cost curve by taking in consideration hydroelectric, geothermal, fossil fuel generation costs and NO\textsubscript{x} emission costs as well. Even though the costs associated with power generation surged between 1998-2000, they show that during the summer of 1998 market power represented a quarter of total electricity expenditures, whereas in mid 2000 the specific proportion had increased in half. Those findings are also confirmed by Joskow and Kahn (2002), who argue that higher prices observed in California reflected the suppliers’ exercise of market power.

In general, the potential of market power exercise is a distinguished characteristic in the power sector. Birnbaum et. al (2002) argue that investors are able of keeping less capacity in the power industry, in order to drive the market in tightness and subsequently take advantage of higher prices. They argue that electricity prices tend to rise at lower levels of capacity utilization relative to other commodities because of the lack of substitutes and inventories. In order to confirm that view they employ data from the PJM Interconnection and conclude that an increasing trend in prices is observed at a level well below the full capacity of generation, i.e., a utilization rate of 80% to 85%, while in the chemical industry the corresponding rate exceeds 90%.
2.3 Electricity spot prices, main characteristics

Spot prices in many commodities exhibit deviations around a mean level, known as the long-run equilibrium level. This property is described by the term mean-reversion and is mainly evident in the financial and energy markets. In the latter case however, mean reversion is more pronounced because weather, transportation, storage and technological advances have a major impact on price determination. Schwartz (1997) proposes a mean reverting spot price model (that follows a stochastic process) of the form:

\[ dS_t = \alpha (\mu - \ln S_t) dt + \sigma_t S_t dz_t \]  \hspace{1cm} (2.2)

where \( dS_t \) refers to the change of the spot price \( S_t \), \( \sigma_t \) is the volatility (or standard deviation) of the spot price, \( \mu \) is the long term mean and \( \alpha \) is the mean reversion rate, which is strictly positive. The term \( \sigma_t S_t dz_t \) represents the stochastic term of the process with \( z_t \) being a standard Wiener process\(^4\). If the spot price is above the long term level (\( \mu \)), the drift of the spot price will be negative and the price will tend to revert back to \( \mu \). In contrast, if the spot price is below the long term level, the drift will be positive and the price will tend to move towards \( \mu \).

In addition, electricity prices are subject to seasonality and non-normal characteristics such as positive skewness and excess kurtosis. Excess kurtosis\(^5\) denotes that lower or higher prices are more probable to occur compared to the normal distribution, whereas positive skewness\(^6\) indicates that high extreme values are more common than lower ones. Furthermore, empirical findings suggest that time varying volatility in electricity prices is related to demand and supply conditions, the level of trading volume and the mix of fuels used in generation process that is also affected by regional characteristics (weather, hydro availability, other energy infrastructures).

Knittel and Roberts (2001) examine the behaviour of electricity prices in California after deregulation and find that they significantly differ from equity prices. They employ hourly electricity prices to show that prices are on average higher during the weekdays when demand for power increases. Moreover, prices exhibit seasonal components and censoring from above. They also detect volatility that tends to be higher in the occurrence of positive shocks, which is attributed to the convex marginal cost curve of power generation.

\(^4\) A standard Wiener process \( Z = \{ Z_t, \ t \geq 0 \} \) is a continuous stochastic process with independent increments: \( W_t = 0 \), \( E \{ W_t \} = 0 \) and \( W_t - W_s \sim N(0, t - s) \)

\(^5\) Pearson has proven that excess kurtosis is observed when the coefficient takes values higher than 3. In this case the distribution is called platokurtic. Normal distribution has kurtosis equal to three.

\(^6\) Positive skewness exists when the measure takes values higher than zero. In this case it is said that the distribution is positively skewed. In the normal distribution the skewness coefficient is zero.
Escribano, Pena and Villaplana (2002) employ data from the power markets of Argentina, Australia, New Zealand, NordPool and Spain to show that volatility, positive skewness and kurtosis are due to the regional characteristics of each of the markets examined. Moreover, prices are mean reverting, except in the NordPool due to the extensive use of hydro resources in power generation that ... Likewise, by employing a Generalized Autoregressive Conditional Heteroskedasticity (GARCH) model that takes account of the non-constant variance and the outliers that power prices exhibit, the authors conclude that volatility in the price series is persistent.

**Textbox 2.1: The characteristics of a GARCH model**

The GARCH model is a generalization of the Autoregressive Conditional Heteroskedasticity (ARCH) model, which proposes that an asset’s variance depends on the squared terms of the previous time periods. Assuming a return \( X \), then the GARCH specification, as suggested by Bollerslev (1986), is given by the following equations:

\[
\begin{align*}
X_t &= \mu + u_t \\
u_t | I_{t-1} &\sim N(0, \sigma^2) \\
\sigma^2_t &= \omega + \alpha u^2_{t-1} + \beta \sigma^2_{t-1}
\end{align*}
\]  

(2.3)

Returns in the mean equation are expressed as a random walk process, whereas the error term \( u_t \) which is assumed conditional on past information, follows the normal distribution with a zero mean and a constant variance.

The conditional variance \( \sigma^2_t \) is given as a function of a constant, the ARCH term \( u^2_{t-1} \), which represents the news about volatility from the previous period and the GARCH term \( \sigma^2_{t-1} \) that represents the forecast variance of the previous period. The sum of \( \alpha + \beta \) represents the persistence of volatility. Volatility is said to be persistent if today’s return has a large effect on the variance forecasted in periods ahead. This effect is known as volatility clustering, implying changes of the same magnitude. If \( \alpha + \beta < 1 \) then shocks are transitory in nature, while if \( \alpha + \beta > 1 \) the volatility forecast is explosive.

Hadsell, Marathe and Shawky (2004), study the behaviour of US wholesale electricity prices in the California-Oregon Border (COB), Palo Verde (PV), Cinergy, Entergy and the PJM markets. Sample statistics on spot prices by market confirm the persistence of volatility in all markets examined. In the COB and the PV markets particularly, the relatively fixed power prices observed in the mid 90’s, were followed by significant increases after restructure took place. For instance, in the COB market the average price per KWh reached $185 in 2001, whereas some years before it did not exceed $20 per KWh.

Hadsell and Shawky (2006) examine the volatility characteristics of day-ahead and real time electricity prices in the New York Independent System Operator (NYISO)\(^7\) market in order to document the impact of transmission congestion observed when the flow of electricity on a transmission path equals its physical limit. They find evidence that prices during the peak hours, when the possibility of congestion is more usual to occur, are subject to significant

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\( ^7 \) NYISO is a non-profit organization, which is in charge to operate the wholesale electricity market in the New York State. Eleven geographic zones are traded on NYISO, each one treated as separate but connected to other markets.
variation. Moreover, average day-ahead peak prices were lower in zones of little congestion, while they tended to increase in zones where costs due to congestion had increased. Using a GARCH(1,1) model they detect a time varying volatility, especially in the case of day-ahead prices. Finally, they test the impact of congestion in real time prices by adding lagged values of the marginal cost of congestion in the GARCH specification and conclude that the increase in volatility is related to higher congestion.

Similarly to electricity prices, demand for electricity is subject to seasonal and random variation both in the short and the long term period, since it is affected by weather conditions and the economic activity. Meneu et al. (2001) suggest that a non-linear relationship between load and temperature exists, which causes increased load volatility across time. For that reason, the behaviour of load can be captured by a mean reverting process. Potential increases in temperature will increase demand for power due to additional needs for electricity. This increase (shock) however, will decline as demand for power progressively falls. In terms of mean reversion, load will be higher than average and will tend to revert to its long-term level as the temporary shock fades (negative drift). In contrast, during periods of lower demand (for instance holidays or weekends), load will be below its equilibrium level with a positive drift indicating the return to the mean level.

Pirrong and Jermakyan (1999) model load, according to the properties of mean reversion and argue that the half life of a load shock, i.e., the time required for a variable to return half way back to its mean -under the condition that no additional random shocks occur- is less than 12 hours. As far as electricity demand and spot prices are concerned, they argue that they are highly correlated. As load increases, units with higher operational costs are dispatched by the system operator to supply power into the grid, hence the wholesale price increases. For that reason they propose that a convex relationship can suitably describe the relation between them.

The specific functional form is also suggested by Skantze and Ilic (2001), Barlow (2002) and Skantze et al. (2004). Barlow (2002) assumes a non random, independent of time supply function and derives the spot price in relation to a stochastic demand process. The latter is modelled as an Ornstein-Uhlenbeck process and by considering electricity price to be convex function of load he introduces a relationship that captures spikes in prices.

Skantze et al. (2004) model the spot price as a function of demand and supply shifts. The market clearing price at time $t$ is assumed to be given from the relationship:

$$ S_t = e^{\alpha L_t + b_t} $$

(2.4)

where $\alpha$ is a fixed parameter, $L_t$ denotes the level of demand at time $t$ and $b_t$ is a stochastic supply process. Both $L_t$ and $b_t$ are derived upon deterministic and stochastic processes. In the case of load for instance, the deterministic part represents the average monthly load, which varies among observations as the demand for electricity evolves over the year.
2.4 The futures markets and the main theories on the pricing of their contracts

This section reviews the main studies proposed on the pricing of futures contracts. Futures contracts are binding agreements between sellers and buyers for the delivery of an asset at a specified future date with agreed upon payment terms.

They are standardized financial instruments with respect to the commodity’s quantity, the payment terms, the date and the location of delivery. Standardized trading through the contract’s specifications ensures that the commodity being traded in every contract is identical. At the delivery date, both parties of the futures contract have the obligation to accomplish the asset’s delivery under the terms specified by the contract.

Investors can hedge their actual positions in the cash market by selling or purchasing futures contracts. The purchaser of the futures contract is said to have a long position in the futures market, whereas the seller of the contract holds a short position. The transaction according to which, market participants seek a means to protect an existing asset position from adverse price movements in the future, is known as hedging. Through hedging, investors expect that the risk of a loss will be smaller than that if the position had remained unhedged. In other words, they anticipate that the prices in the actual and the futures markets will move in that way so as to avoid losses (or earn profits) from the transaction.

Assuming for instance, an investor who possesses the commodity in the spot market. In order to hedge from an unexpected price decrease the investor can choose to sell futures contracts for the delivery of the commodity at a specified price, quantity and location; hence the investor will take a short position in the futures market. The long position in the spot and the short position in the futures markets are opposite and in this way they offer a protection
against the risk of declining prices in the spot market. Therefore, the loss in the spot market from selling the commodity at a lower price is being offset by the profit made from the sale at the higher price of the commodity in the futures market (Figure 2.1).

**Figure 2.2: Payoffs from a long hedge**

Respectively, an investor who does not possess the commodity in the spot market is said to be short or the consumer of the commodity. In order to hedge from a potential price increase in the future, he can enter the futures market and buy contracts at a pre-specified price, i.e., he will go long in the futures market. As in the previous case, the positions are opposite and the investor gains a means to protect from the risk of rising prices in the spot market. If the spot price of the commodity increases the loss in the cash market is being offset by the gain made in the futures market and vice versa (Figure 2.2).

As the two parties in the futures market face the counter-party risk, the exchange provides both sides a securing mechanism that the contract will be honored. This is made through the exchange’s clearinghouse, which acts as intermediary in futures transactions. The clearinghouse ensures that sufficient funds are available to cover each trader’s obligations, since it requires from traders (through a commission merchant or a broker) to deposit money at the initiation of the trade. This deposit is usually referred to as the initial margin deposit. Each trader’s margin money is maintained in a separate account, which is adjusted on a daily basis to reflect gains or losses in the contract’s value. This process is known as “marking to market” because the account is adjusted to reflect the current market value based upon the closing or settlement price. Although, the margin requirements are small relative to the total value of the contract, traders of the futures contracts are secured in this way from the possibility that the other side of the contract will default on the financial obligation.
It should be also mentioned that in most of the cases, a futures contract does not actually result in the delivery of the underlying commodity. Instead, most investors prefer to settle their futures obligation by closing out their initial position in the futures market. Thus, in the case of a long position in the futures market, the investor closes his position by buying back the contract, whilst in the case of an initial short position the trader buys the futures contract. The main difference compared to forward contracts, which are also agreements to buy or sell an asset at a specified price and time in the future, is that the latter are traded in OTC markets directly between the seller and the buyer of the contract (custom-tailored supply contracts). Figure 2.3 illustrates the agreement in forward (upper part) and futures contracts respectively, with the main difference being the clearinghouse in the futures market.

2.4.1 The theory of normal backwardation

The theory of normal backwardation suggested by Keynes, proposes that in a market where hedgers hold predominantly short positions to avoid the risk of unpredictable price changes, the price of a futures contract should be a downward biased estimate of the expected future spot price at the date of the contract’s expiration. The discount of the futures price relative to the expected spot price represents the risk premium that hedgers are willing to pay and speculators respectively demand in order to assume the risk of a price imbalance.

For example, a producer of grain would be willing to sell grain futures, “lock” in the futures price of his crops and obtain in this way insurance against the price uncertainty of grain at harvest time. Speculators respectively, would provide this insurance and buy futures at a price below than that expected at the maturity of the contract. Thus, by “backwardating” the futures price relative to the expected spot price, speculators receive a premium from producers for assuming the risk of future price fluctuations.
Hicks (1939) asserts to Keynes’ view by arguing that short term investments are preferred by risk-averse investors. For that reason, long-term bonds should have higher interest rates than short-term bonds in order to compensate investors for the higher price volatility. In other words, the issuers of long term bonds in order to induce investors to hold this type of instruments they would have to pay them a liquidity premium. According to the liquidity premium hypothesis, the term structure of interest rates should be an increasing function of maturity. Assuming $F_{t,T}$ to be the price of a futures contract traded at time $t$ for delivery at a future date $T$ and $S_T$ to represent the spot price at the date of delivery (time $T$), the normal backwardation hypothesis is given by the relationship:

$$F_{t,T} = E_t[S_T] - \text{Risk premium}_{t,T} \quad \text{(2.5)}$$

Keynes argues that risk-averse speculators will not have to hold the futures contract until the date of expiration. As the maturity date draws close, the futures price will start to approach the spot price of the commodity.

**Figure 2.4: The cases of contango and normal backwardation**

Then, they can profit by selling futures contracts in order to offset their initial long position. In contrast, futures contracts traded at prices higher than expected spot prices, describe a market situation known as normal contango. Contango is met when significant number of hedgers are willing to buy futures contracts (long hedgers) and in this process they bid futures prices up to attract speculators. The resulted premium relates to the higher price the futures contract is sold relative to the expected price at the date of delivery:

$$F_{t,T} = E_t[S_T] + \text{Risk premium}_{t,T} \quad \text{(2.6)}$$
As the day of expiration approaches and irrespective of whether the market is in backwardation or in contango, the futures price will converge to the expected spot price, otherwise a threshold for risk-less arbitrage opportunities will exist (Figure 2.4).

### 2.4.2 The cost of carry (or storage) theory

The theory of storage suggests that for storable commodities the difference between the futures and the spot prices should reflect the commodity’s carrying charges. Those charges represent the cost of storage, primarily warehousing and insurance costs and in addition the foregone interest from investing money in warehousing costs rather than in other investment opportunities. If the spot price diverges from the futures price then arbitrage opportunities will arise, enabling traders to realize a risk-less profit.

The foundations of the theory of storage are attributed to Kaldor (1939), Working (1942, 1949), Brennan (1958) and Telser (1958). Kaldor (1939) introduces the notion of convenience yield that represents the return accruing from holding a commodity in order to explain the reason that commodity’ stocks are carried when prices are in backwardation. Kaldor argues that in an uncertain environment, the commodity is subject to speculation and for that reason producers should have an incentive to hold inventory.

![Figure 2.5: Working’s storage supply curve](image)

The amount of inventory, the speculative inventory as he defines it, represents the excess of stocks over normal requirements, which is held in the expectation of a price increase. This incentive is the convenience yield deducted from the carrying costs (warehousing cost and interest payments), which is comprised in the difference between the futures prices and the higher expected prices, i.e., the risk premium suggested by Keynes.
Working on the other hand, was critical on Keynes’ view that futures markets exist as risk transfer mechanisms between hedgers and speculators. His contribution to the development of the theory of storage is substantial. In his 1948 study on the characteristics of wheat cash and futures markets, Working observed that in some occasions the spot prices tended to be higher than the futures price or alternatively futures prices for deferred delivery were lower than futures prices for nearby delivery. Furthermore, by examining the relationship between the difference in a commodity’s price for delivery in two different dates (the carrying charges) and the level of wheat inventory he finds that the specific spreads represent prices of storage relative to the level of stocks kept in storage.

In his 1949 study, Working argued that a positive difference between deferred and near futures prices contracts should represent the costs of carrying the commodity within the specific dates. If stocks to be stored are exceptionally large, then the return for carrying the commodity should exceed the cost of storage. In this case, the price of the commodity for deferred delivery exceeds the price of the nearby contract by the amount of the necessary return between the specific dates. Therefore, the return for storage, since the price of storage is not directly quoted, should be given from the price difference of the two futures prices.

However, Working was particularly interested in explaining the observation that inventories are held even when negative price differences in the market are observed, which happens when the price of nearby futures contracts are higher than the price of deferred contracts. According to his perspective, this is associated with the fact that smaller amounts of inventory carry a specific return, i.e. the convenience yield. By the time that certain amounts of storage are supplied even when the price of storage is zero (Figure 2.5), means that to those suppliers engaged in merchandising or in processing, storage facilities act supplementary in their business. Therefore, the notion of convenience yield is considered as, either the utility gained by the firm from having the ability to supply its customers in a commodity’s scarcity, or the profit from selling the commodity at a higher price due to the commodity’s supply shortage. Therefore, in times of scarcity convenience yield becomes sufficiently larger than storage and financing costs, leading in this way to negative carrying charges.

Brennan (1958) and Telser (1958), generalized Working’s insight by suggesting theoretical models on the supply for storage theory. Brennan postulates that in addition to the marginal expenditure on physical storage and the marginal convenience yield, the price spread should be also explained by a risk premium factor emerging from stock holding. According to his proposition, for a level of stocks carried out at period $t$ ($I_t$), the commodity’s net marginal cost of storage $m_t(I_t)$, is equal to the marginal outlay on physical storage $o_t(I_t)$, the risk aversion factor $r_t(I_t)$, less the marginal convenience yield $c_t(I_t)$:
The total outlay, which is the sum of storage, insurance and interest costs, is assumed to be an increasing function of the inventory held by a firm. Respectively, the marginal outlay is expected to be approximately constant until total warehouse capacity is utilized. The convenience yield is assumed to be negatively related to the level of inventory, whereas the risk-averse factor to be an increasing function of stocks. This behavior is explained on the grounds that, the greater the necessary investment to carry stocks the higher the loss likelihood will be. According to Brennan, if a small quantity of stocks is held, then the risk for undertaking an investment in stocks will be also small. In contrast, if a substantial amount of stocks is held, then a potential price loss would lead to significant losses due to the high investments required.

Brennan in addition, extends the theoretical propositions on the specific perspective by testifying his model empirically on three semi-perishable (eggs, cheese, butter) and two durable (wheat and oats) farm commodities. He treats the lack of futures prices by using approximations on expected future prices, by considering a trend in spot prices adjusted by a seasonal pattern. For these commodities, Brennan plots the relationship between end of month stocks and net marginal storage costs - measured as the inter-temporal price spread less the marginal outlays for physical storage - and concludes that the price spread is negative at lower levels of inventories, indicating in this way the presence of a positive convenience yield.

Similarly to Working and Brennan, Telser (1958) was also sceptical on Keynes' view that futures prices are downward biased estimators of the expected spot prices. His empirical study provides evidence of the negative relationship between inventories and convenience yield. According to Telser, the magnitude of the price spread and subsequently of the convenience yield is affected by the seasonal pattern that stocks exhibit. This is especially observed in grain futures contracts, where the harvest cycle determines the pattern of stock keeping. In this case, convenience yield tends to rise before harvest when stocks are lower and decrease after harvest when abundant supplies of the commodity exist.

Under the preceding presumptions the theory of storage is summarized in the relationship:

\[ F_{t,T} = S_t (1 + r_{t,T}) + SC_{t,T} - Z_{t,T} \]  

(2.8)

where \( S_t \) is the commodity's spot price at time \( t \), \( r_{t,T} \) the interest rate, \( SC_{t,T} \) the storage cost and \( Z_{t,T} \) the convenience yield. The main implication of the theory of storage is that the return from purchasing the commodity at time \( t \) and selling it for delivery at time \( T \), \( F_{t,T} - S_{t,T} \), is equal to the interest foregone, \( r_{t,T} \cdot S_t \), plus the cost of storing the commodity for the time period held less the convenience yield. The difference between the futures price and the concurrent spot price is known as the basis.
The normal backwardation and the storage theories have stimulated the researchers’ interest to test whether and at what extent the proposed implications were applicable in the commodity markets. As far as the theory of normal backwardation is concerned, Houthakker (1957) opposed to Telser’s finding that no risk premium exists in the wheat and cotton futures prices. Houthakker finds evidence of the Keynes’ hypothesis by considering data from the US wheat, corn and cotton markets. He examines the open commitments in the futures contracts and their prices as well, in order to estimate and analyze any possible gain earned in the futures markets. The commitments are divided between hedging and speculative and for each position Houthakker estimates the profit or loss, as the difference in the average prices at the date of the contract’s expiration and initiation respectively multiplied by the volume of the futures contracts in each commitment. By arguing that futures trading, aims at transferring price risks from hedgers to speculators, he shows that large speculators make profits on their long position in all three commodities. According to Houthakker, this is an indication of risk premium, since the futures price tends to rise in the time interval between the contract’s initiation and the delivery date.

Likewise, Cootner (1960) extends the theory of Keynes that speculators earn a return in the futures market. Cootner argues that hedgers like producers can be commodity consumers as well, hence they can either hold short or long positions in the futures market. This implies that when commercials are hedging stocks, the commodity’s futures price should be expected to fall and vice versa. Cootner finds evidence on the specific argument in the wheat futures market. By using wheat inventories as a proxy of hedged stocks and he that speculative positions followed the high and low level of the commodity’s stocks.

Moreover, Williams (1986) proposes that firms hold commodities below full carrying charges because of the transaction costs incurred, when shortfalls in inventory constrain the immediate purchase in the cash market. Williams argues that even a risk neutral stockholder, will be willing to pay a premium in order to avoid the specific type of “shortage” costs. According to his argument, the premium represents the difference between cash and futures prices in the case of inverse carrying charges.

Furthermore, Williams and Wright (1989) questioned the notion of the convenience yield in the commodities’ futures markets. In contrast to the cost-of-carry theory, they define the price of storage as the difference between the carrying costs and the expected rate of change of the price for immediate delivery. Their model incorporates the relationship between backwardation and the amount of inventories stored, as identified by Working’s supply of storage curve, even though they do not incorporate in their analysis the notion of convenience yield. In addition, they assume commodities, which are economically distinct but

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8 The specific division stems from the Commodity Exchange Act (CEA), which classified at the time of Houthakker’s study, futures commitments in hedging or speculative, according to certain reporting limits (i.e., 200,000 bushels in the case of wheat and corn and 5,000 bales in the case of cotton) on futures contracts that must be communicated from traders to the CEA.
related so that they can be commonly aggregated for reporting prices and quantities (they use as an example the case of corn in two different states, Iowa and Louisiana). According to their model, if price spreads are lower than total carrying costs, storage should take place not because of the convenience yield related in keeping readily available stocks, as Working postulates. Instead, stock holding should represent a beneficial way of minimizing transformation costs of one commodity into another, by minimizing transportation, marketing and processing operations.

Deaton and Laroque (1992) examine the spot price characteristics of thirteen commodities and find that they display positive skewness, kurtosis and high volatility. They propose that fluctuations in future spot prices are related to the level of inventories. Inventories can absorb unexpected demand shifts or supply shortages, leading in this way to less volatile spot prices. In the absence of inventories the price is determined by the demand level and the available harvest and by simulating the relationship between current and expected future prices they find that the level of prices is interrupted by upward price movements. According to the authors, the inability of market participants to hold negative inventories -no transfer of commodities can take place from the future to the past, affects the pricing of commodities leading to non-linear price relationships.

Brennan D., Williams and Wright (1997) challenge the smoothing role of inventories by explaining the supply of storage curve on the grounds of locally determined stocks and prices. By examining the wheat market in a region of Australia, they argue that due to transportation costs it would be more profitable for the commodity to be stored and transported to the main receival point during the off-peak period rather than during the peak period, which is the months following the harvest. By plotting inter-temporal spreads, i.e., the difference between off-peak and peak prices, against aggregate stocks they derive a supply of storage curve similar in shape to that suggested by Working (Figure 2.5). The result, according to the authors, implies that gains from stockholding can only emerge if appreciations on the stock’s value occur when these are kept in locations different from the receival point (i.e., a positive local inter-temporal price spread). This argument is contradictory to the supply of storage proposition that the difference between nearby and distant prices for the same commodity —either negative or positive, reflect the return from storing the commodity.

Bessembinder (1992) studies the effect of net hedging positions, defined as the difference between long hedge and short hedge contracts and the systematic risk of the risk premium. His study includes 22 futures contracts (financial, agricultural, foreign currency and mineral), while the systematic risk is based on the beta coefficient of a US stock market index and macroeconomic variables, such as inflation and the change in real short-term interest rates.

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9 The receival point refers to the main port of the region in which the crop from different areas is gathered in order to be exported.
Bessembinder tests the relationship between returns and systematic risk and concludes that in the majority of the markets examined the relationship is nonzero when it is conditioned on the net hedging demand. Moreover, the beta estimates indicate that many futures positions are subject to nonzero systematic risk, which is consistent with Keynes’ view that the hedging pressure causes futures prices to contain an expected time trend.

On the other hand, many studies in the literature of futures pricing find evidence to support the predictions of the storage theory. Samuelson (1965) theoretically demonstrates that changes in spot and futures prices will be of similar magnitude if demand or supply shocks occur in periods of abundant inventory levels. However, fluctuations in spot prices will be more excessive than in the futures price at lower levels of inventory.

Dusak (1973) examines the existence of risk premium in futures trading in the context of the Capital Asset Pricing Model (CAPM). According to this approach, the risk premium on a futures contract has a different perception to that of Keynes, since it should depend on the systematic relationship of variations between the prices and the return on total wealth. If no systematic risk exists -which means that the risk of a futures contract is not related to the risk of the changes in the market’s portfolio value, then no insurance payment should be made to investors for the potential risk that may bear. In contrast to Dusak’s argument, the Keynesian approach suggests that the risk from futures trading emerges only from price variations in the spot and the futures market. Dusak employs three commodity markets -wheat, corn and soybean, in order to test both types of risk and concludes that their futures contracts are not risky assets.

Gibson & Schwartz (1990) emphasize on the importance of convenience yield in the relationship between spot and futures oil prices. They propose a two factor model for the valuation of oil contingent claims under the assumption that the oil price and the convenience yield follow a stochastic process. They test their assumption for oil prices using weekly futures oil prices and find a mean-reverting process for the convenience yield and a positive correlation coefficient with the spot price.

Fama and French (1987) use monthly data from 21 commodity futures to examine variation in the basis and whether the latter has information content in the futures risk premium, by employing the relationship:

\[ \frac{F_{t,T} - S_t}{S_t} = \sum_{m=1}^{12} \alpha_m d_m + \beta R_{t,T} + \varepsilon_{t,T} \]  

(2.9)

where \(d_m\) represent a dummy equal to 1 if the futures contract matures in month \(m\) and 0 otherwise and \(R_{t,T}\) represents the interest rate (beginning of monthly yields on Treasury bill).

\[ \text{The term } \left( F_{t,T} - S_t \right) / S_t \text{ is used alternatively to denote the basis as a percent of commodity price. It stems from equation (2.8) by dividing each term of the relationship by } S_t. \]
The results obtained indicate that the basis varies with the change in interest rates, while the existence of seasonality is considered as a proxy for the convenience yield, since inventories in agricultural commodities tend to be lower prior to harvest. They also show that the theories of storage and normal backwardation are alternative but not controversial. They propose that the basis can be also expressed as the sum of two components: the premium and the expected change in the spot price:

$$F_{t,T} - S_t = \text{Risk Premium}_{t,T} + E_t \left[ S_T - S_t \right]$$  \hspace{1cm} (2.10)

where the premium is the bias of the futures price as a forecast of the expected spot price:

$$\text{Risk Premium}_{t,T} = F_{t,T} - E_t \left[ S_T \right]$$ \hspace{1cm} (2.11)

Therefore, in the specific theory, basis is explained on the ground of the existence of a risk premium transferred from hedgers to speculators. The risk premium can be positive or negative and due to that reason the basis can take positive or negative values.

In addition, Fama and French (1988) test the theory of storage by introducing the concept of the interest adjusted basis. Interest adjusted basis is used as a proxy for inventories due to the lack of available data on storing reports. Specifically, they use the sign of the interest-adjusted basis by employing the spot and the futures prices and propose that a negative sign should be associated to low inventory level and higher variation in spot prices relatively to futures prices. In contrast, when inventory levels are high, the difference between spot and futures prices should be small, leading to a positive interest adjusted basis. In a similar manner, Ng and Pirrong (1994) use the interest adjusted basis to examine the impact of the spread between spot and futures prices in industrial metals and find evidences in favour of the storage theory. Pindyck (1994) proposes that the convenience yield that accrues from holding a commodity resembles to equity’s dividend payment. Similarly to the preceding findings, Milonas and Henker (2001) examine spot and futures prices of Brent and WTI crude oil and find significant convenience yields, which exhibit monthly and yearly seasonality.

### 2.5 Convenience yield as the value of a call option

In the literature, the convenience yield from commodity futures pricing has been also approximated to the trading behaviour of a financial call option. A call option is a financial contract that gives the opportunity to its buyer to purchase an asset at a specified price, known as the exercise price. In case the asset’s market price is higher than the exercise price, the buyer of the contract has a certain benefit to exercise the option and purchase the product at the lower specified price. His profit will be the difference between the spot and the exercise price, less the price or premium that he initially paid to purchase the contract.

Heinkel, Howe and Hughes (1990) empirically test the relationship between convenience yield and the level of inventories and find that the former is decreasing in aggregate inventory.
Moreover, they argue that the marginal costs of production can influence the convenience yield. The specific argument is related to the fact that the existence of inventories can be beneficial for a firm facing higher marginal costs of production. It can be therefore, cost effective for the firm to cover demand from existing stocks rather than making a new production at a higher cost. As more stocks however are used, the level of inventories will fall and subsequently the convenience yield should increase. According to the specific relationship, Heinkel et al. propose a two period model in which convenience yield behaves like a call option.

Similarly, Milonas and Thomadakis (1997) use a three-period model that involves the crop, the harvest and an intermediate period, in which the producer has to take a decision on whether he will sell the commodity in harvest or store it for later use. The futures price is given by the relationship:

\[
F(0,1) = S(0) + C(0,1) - Z(0,1)
\]  

(2.12)

where \( F \) is the futures price at time 0 for delivery at time 1, \( S \) is the spot price at time 0, \( C \) denotes the carrying charges, while \( Z \) is the convenience yield accruing to the holder of the commodity for the specific time period. Assuming an intermediate time period \( t \) the producer can decide to hold the inventory until time 1 or sell at the specific date. He will have the incentive to sell if at time \( t \) the spot price exceeds the futures price, i.e., if:

\[
S(t) - F(t,1) + C(t,1) > 0
\]  

(2.13)

Subsequently, the value of the convenience yield \( Z(0,1) \) can be considered as a contingent claim with a payoff:

\[
\max \{0, S(t) - F(t,1) + C(t,1)\}
\]  

(2.14)

which is the payoff that can be earned by the holder of a call option with a strike price \( F(t,1) \).

2.6 Spreads between futures contracts

A spread is the price difference between futures contracts on commodities related through their production process. Options on futures spreads have been introduced during the last decades for a significant number of products. This class includes the crack fuel spread, the NOB spread on Treasury Notes and Bonds, the FRAC spread between propane and natural gas, the TED spread which involves Treasury bills and Eurodollars and the crush or soybean complex spread.

The crush spread, comprises futures contracts of soybean and the refined products soymeal and soyoil. The spread that takes its name from the crush process of soybeans, offers to the market participants an indication of the average gross processing margin. Since soybeans, meal, and oil are priced differently conversion factors are needed to equate them when calculating the spread. According to the United States Department of Agriculture (1988) the
crush of one bushel (60 pounds) of soybeans produces 48 pounds of meal and 11 pounds of oil hence, the value of the crush spread in dollars per bushel is given by the equation:

\[
\text{Gross Crush Margin}_t = \frac{[(\text{Soymeal}_t \times 48)]}{2000\text{lbs}} + \frac{[(\text{Soyoil}_t \times 11)]}{100} - (\text{Soybean}_t) \tag{2.15}
\]

where Soymeal\(_t\) is the futures price of meal per ton, Soyoil\(_t\) is the futures price of oil per 100 pounds and Soybean\(_t\) is the futures price of soybeans per bushel.

Respectively in the energy markets, spreads are mainly used as a means of quantifying the cost of production of refined products from raw materials used to produce them. The most well known spread options are the crack spread and the spark spread options. A crack spread, involves the simultaneous purchase (sale) of crude oil against the sale (purchase) of refined petroleum products. The specific trading instruments were introduced in October 1994 by the NYMEX, with the intention to offering a new risk management tool to oil refiners. The most popular crack spread contracts are computed on daily futures prices of crude oil, heating oil, and unled gasoline.

The 3 : 2 : 1 crack spread comprises three contracts of crude oil, two contracts of unleaded gasoline, and one contract of heating oil, with the mathematical expression given by the formula:

\[
\text{CS}_t = \frac{2}{3} [\text{UG}_t] + \frac{1}{3} [\text{HO}_t] - [\text{CO}_t] \tag{2.16}
\]

where UG\(_t\) denotes the unleaded gasoline futures contracts, while HO\(_t\) and CO\(_t\) the heating and crude oil futures contracts respectively.

The statistical properties of the crack spread options have been extensively studied in the literature of energy markets. For instance, Serletis (1992) examines the empirical finding that energy futures prices exhibit random walk behaviour by implementing unit root tests for the univariate case of daily crude oil, heating oil and unleaded gasoline time series. His findings suggest that the unit root hypothesis can be rejected if he allows for a one time break in the intercept and the slope of the trend function at a certain points in time.

Peroni and McNown (1998) examine the degree of bias and consistency for certain parameters in order to test the efficient market hypothesis in the oil futures market. They employ monthly observations on spot and futures prices for West Texas Intermediate crude oil and unleaded gasoline. The series fail to reject the unit root hypothesis, while they are found to be cointegrated. Moreover, an indication of market inefficiency exists since the tests on the residuals (the difference between spot and futures prices) are serially correlated. Similarly, Girma and Paulson (1999) examine the pricing relationship between crude oil, unled gasoline and heating oil futures prices and conclude that the futures prices of those products are cointegrated and the same is true for the spreads as well.
On the other hand, a spark spread can be considered as a proxy for the cost of converting a specific fuel, usually natural gas in electricity at a specific facility. It is the primary cross commodity transaction in electricity markets, which is defined as the difference between the price of electricity sold by a generator and the price of the fuel used to generate it, provided that these prices are expressed in appropriate units. The most commonly traded contracts include the 4:3 spark spread that involves four electricity futures contracts and three contracts of natural gas and its value is given in $ per MWh by the expression:

$$\text{Spark Spread} = 4 \times \text{Futures electricity contracts} - 3 \times \text{Futures natural gas contracts}$$  \hspace{1cm} (2.17)

By buying natural gas futures at a relatively low price and selling electricity futures at higher price, the power producer is said to have sold the spread, hedging in this way his profit margin for a physical sale.

Emery and Liu (2002) test the relationship between electricity and natural gas futures prices, through the spark spread using daily settlement prices from the California Oregon Border and the Palo Verde markets. They define the spark spread, as the gross profit earned by buying natural gas and burning it to produce electricity, whereas energy prices and the generator’s efficiency determine the size of the profit margin. The gross generation profit margin is given by the relationship:

$$\text{Gross generation Profit Margin} = \left[ \text{Price of Electricity} \right] - \beta \times \left[ \text{Price of Natural gas} \right]$$  \hspace{1cm} (2.18)

where the price of electricity is per MWh at time t, $\beta$ is the generator’s heat rate and natural gas price represents the cost of a million Btus (MMBtu). The spark spread trading strategy considered involves the purchase of five electricity futures contracts and the sale of three natural gas futures contracts. The specific relationship implies that 8,152 MMBtu are required to produce 1 MWh of electricity hence; the specific value represents the heat rate. Using nearby COB and PV electricity and Henry Hub natural gas daily settled futures prices in connection they obtain a data set for the gross generation profit margin.

Diagrammatic representation of daily electricity and natural gas futures prices shows the presence of seasonality appearing in electricity prices, while variation in natural gas futures prices is less pronounced. As far as the electricity as a commodity is concerned, seasonality reflects the demand for cooling needs, especially in the Palo Verde region during the summer months. Seasonal patterns are evident in the average gross generation profit curve as well. According to the authors, the regional and seasonal differences reflected in the spark spread,

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11 Each power futures contract defines the delivery of 736 MWh of electricity during the peak hours every month, whereas a futures contract of natural gas defines the delivery of 10,000 MMBtu. The specific trading strategy (5:3) implies that 30,000 MMBtu are needed for the generation of 3.680 MWh or 30,000 / 3.680 = 8,152 MMBtu per MWh.
are related to the commodity’s non-storable nature and the physical barriers of power transmission (there is a certain amount of load that power line equipments can carry).

Eydeland and Geman (1998), propose that a portfolio of daily options on spreads between electricity and the fuels used in its generation process comprises a safe hedging procedure. They suggest that the specific process is equivalent to the decision of leasing or owning a power plant. They demonstrate this presumption by arguing that the decision to run a power plant should be taken if only the price of electricity exceeds the cost of the fuel and the operating costs as well, i.e.,

\[
\text{Net Profit} = \max \left\{ \text{Price}_{\text{electricity}} - \frac{\text{Heat Rate}}{1000} \text{Price}_{\text{fuel}} - \text{Operating Costs}, 0 \right\}
\]

(2.19)

The preceding expression of the net profit is similar to the payout of a call option for the spark spread if the operating costs are substituted for the strike price.

2.7 Forward price curves in electricity markets

Electricity forward curves exhibit complicated patterns mainly due to the seasonality effect they exhibit. For that reason, different approaches have been suggested for their construction. One approach is the risk neutral valuation, according to which the price of a futures contract is the risk neutral expectation of the price process. Alternatively, Clewlow and Strickland (2000), propose that the futures curve should be approximated from the estimation the fuel’s forward curve, which is used in the generation process. The specific argument is given by the relationship:

\[
\text{Cost}_{\text{electricity}} = \text{Heat Rate} \times \text{Price}_{\text{fuel}}
\]

(2.20)

On the other hand, Fleten and Lemming (2003) use daily forward prices to construct forward curves for the Nord Pool exchange market. They employ a bottom-up model that takes in consideration determinants of demand and supply for electricity such as temperatures and fuel costs. The results obtained are a set of equilibrium prices and production quantities. For the construction of a series of forward prices an optimization problem is used that incorporates estimated forward prices over a time interval \([T_1, T_2]\). The estimates obtained are constrained to take values within the bid/ask prices observed in the market, i.e.:

\[
\text{F}(T_1, T_2)_{\text{bid}} \leq \text{estimated forward prices} \leq \text{F}(T_1, T_2)_{\text{ask}}
\]

(2.21)

The preceding constraint ensures that the difference between the predicted average summer and winter prices will be equivalent to those observed in the derivative market. According to these values they minimize the squared differences between the forward prices observed in different subperiods of \([T_1, T_2]\) and the bottom up forecasted values subject to the bid/ask constraints. In order to avoid the presence of large jumps in the forward curve they include a
smoothing term in the objective function. The squared differences can capture the shape of the bottom up forecasts relatively to the absolute differences.

Eydeland and Geman (1998) propose that the pricing of futures power contracts should be related to the evolution of fuel prices and demand for power. They propose a relationship in which the price of a futures contract should be given from the equation:

$$F_{t,T} = p_0 + I(t_{t,T}, I_{t,T})$$  \hspace{1cm} (2.22)

where \(p_0\) is the base load price, \(f_{t,T}\) is the forward price of the fuel used in the generation process and \(I_{t,T}\) is the anticipated load at future time \(T\). They also assume that the term \(I\) can take the form \(I = c \exp(\alpha D + \beta)\), where \(\alpha, \beta\) are positive constants and \(D\) dummy variables of the seasonal effect on power prices. The above expression implies that the cost function for the production of power increases exponentially as the demand for fuel increases.

### 2.8 The theory of futures pricing in the electricity market

This section reviews the main studies on electricity futures pricing related to the normal backwardation and the cost of carry theories. Most of the studies in the literature assess the behavior of the risk premium in electricity futures markets, which is related to the futures price and the spot price expected to prevail at the date of the commodity's delivery. The most well known study is that of Bessembinder and Lemmon, which has become a reference point for subsequent theoretical and empirical research with respect to electricity futures pricing.

Bessembinder and Lemmon (2002) introduce an equilibrium relationship by assuming a competitive electricity market with risk-averse power producers and retailers\(^{12}\). The main argument of their model is that prices are determined by the specific market participants and not by speculators, whereas power companies are concerned with the mean and the variance of their profits. Assuming that demand for electricity is exogenous and stochastic, the retailers purchase power either from the spot or the forward market and sell it to their customers at fixed rates. In contrast power generators face increasing to output marginal costs of production.

Demand for forward contracts is related to the risk averse attitude of both market participants, which is formalized through a linear mean variance utility function:

$$E(\text{profit}) - \frac{A}{2} \text{Var}(\text{profit})$$  \hspace{1cm} (2.23)

\(^{12}\) The term retailers describe load serving entities, which are intermediary companies that buy electricity in the wholesale market in order to sell it to final consumers like households. The major risk they face stems from the fact that the price paid for electricity from end customers is regulated and does not adjust to wholesale price that vary along with the marginal cost of power generation. When this occurs the specific entities suffer significant losses from selling at lower price than that they have paid to obtain power.
In this context, they derive the forward price of electricity in relation to the wholesale price \( S_w \) expected to prevail at the date of delivery and its moments, the variance and the skewness:

\[
F_{t,T} = E(S_w) - \alpha \text{Var}(S_w) + \gamma \text{Skew}(S_w)
\]  

The preceding relationship indicates the existence of a premium among the futures and the expected spot prices \( [F_{t,T} - E(S_w)] \), which is positively related to the skewness of the wholesale electricity price and negatively related to its variance. A positive premium – forward price higher than the expected spot price, should be observed when the electricity spot price exhibits positive skewness resulting from convex cost functions. The latter implies that the marginal production costs increase rapidly when demand for power shifts. Given that retail prices are usually regulated, the distributors’ incentive is to hedge against upward wholesale price movements by purchasing electricity at fixed futures prices. Hence, increased demand for futures contracts is likely to cause an upward trend in the forward price compared to the expected spot price resulting in this way into a positive premium.

Respectively, the inverse relationship between the risk premium and the variance of the wholesale spot price is associated with the net hedging demand of retailers as a result of the (positive) correlation between wholesale spot price and retail sales (given that spot prices are usually higher in periods of high demand). In case the retail price is higher than the spot price, retailers’ profits will increase leading to a reduction in their forward purchases and a decline of the forward price as well. If however, the retail price is below the spot price an increase in the forward purchases should take place in order to mitigate their losses.

Shawky, Marathe and Barett (2003) test the relationship between spot and futures electricity prices at the COB market. They find that volatility in the spot price series is at least twice as high the volatility in the futures price series. They also estimate a price series of the forward premium in the form of:

\[
\text{premium} = \frac{F_{t,T} - S_t}{S_t}
\]

Estimation of the trend line shows a positive and statistical significant coefficient of trend, which represents the estimated forward premium. The regression estimate of the particular variable is found to approximate 4% in the sample data employed, which is higher compared to other commodities due to the non-storable nature of electricity.

Moulton (2004) is interested in explaining the initial rapid trading activity in NYMEX electricity futures market, which was followed by a drop and discontinuity. He proposes that this event is primarily due to the unwillingness of participants, mainly speculators, to trade. The author uses data sets of spot pricing and finds that PV and COB spot and futures prices became more volatile after 2000. Although the total number of outstanding NYMEX futures contracts
diminished after 1998, the data indicates that traders used futures contracts primarily to hedge future purchases or sales of the commodity, whilst it is also evident that large scale speculators and small traders have not participated in the market.

Since the NYMEX electricity futures contracts are traded mostly by hedgers Moulton estimates the excess hedging need using the hedging imbalance measure, proposed by Chatrath, Liang and Song (1999):

$$\text{Hedging Imbalance} = \frac{\text{Open Interest from long hedges} - \text{Open Interest from short hedges}}{\text{Total Open Interest}}$$  \hspace{1cm} (2.26)

The plot of the hedging imbalance ratio confirms the existence of seasonal variation, particularly during winter when demand for long positions in the futures market is higher, while short positions in futures contracts dominate during the summer.

Longstaff and Wang (2004) examine the pricing of electricity forward contracts and the relationship between electricity forward and expected spot prices using data from the day-ahead PJM market. They estimate the forward premium in electricity prices as the difference between the electricity forward price observed at time $t$ for delivery during hour $i$ ($i=1,\ldots,24$) of time $t+1$ and the spot price for hour $i$ of day $t+1$:

$$\text{FP}_i = \mathbb{E}_t\left[F_{t+1}^{i} - S_{t+1}^{i}\right]$$  \hspace{1cm} (2.27)

In order to test the existence of forward premia in PJM electricity prices they use the sample mean of the above equation, i.e.:

$$\overline{\text{FP}}_t = \frac{1}{T} \sum_{t=1}^{T} \text{FP}_i$$  \hspace{1cm} (2.28)

According to that measure, they detect the existence of forward premia, both of positive and negative sign, dominated by significant variation, which is attributed to the regular fluctuations in the spot price and the demand for electricity. Additionally, Longstaff and Wang examine the implications of the Bessembinder and Lemmon proposition by regressing the mean forward premia on the variance and the skewness of PJM real time prices. The results obtained are in favour of the proposed relationship since they confirm that the variance of the spot price is negatively related to the forward premium, while the skewness of the wholesale price is positively related.

Douglas and Popova (2008) extend the model of Bessembinder and Lemmon in order to examine the effect of natural gas storage inventories on the forward premium. For that purpose beyond the variance and the skewness measures of the spot price they also include variables, such as the level of gas storage inventories. Their empirical model takes the form:

\[ \text{FP}_t = \text{FP}^* + \beta_1 \text{VAR}_t + \beta_2 \text{SKW}_t + \gamma \text{GAS}_t + \epsilon_t \]

\[ \text{FP}^* = \beta_3 \text{VAR}^*_t + \beta_4 \text{SKW}^*_t \]

\[ \text{VAR}^*_t = \gamma_1 \text{VAR}^*_{t-1} + \gamma_2 \text{SKW}^*_{t-1} \]

\[ \text{SKW}^*_t = \gamma_3 \text{VAR}^*_{t-1} + \gamma_4 \text{SKW}^*_{t-1} \]

The forward premium is estimated according to the specific relationship for each of the 24 hours of the day and for the total sample data ($T$ represents the sample period of 913 days from June 1, 2000 until November 30, 2002).
Chapter 2: Literature survey

**Bessembinder and Lemmon (2002) proposition**

\[
\text{Premium}_t = \alpha_0 - \alpha_1 \text{Var}_{t-1} (S) + \alpha_2 \text{Skew}_{t-1} (S) + \alpha_3 \text{GS}_{t-1} + \alpha_4 \text{CDH}_t + \alpha_5 \text{CDH}_t^2 + \alpha_6 \text{HDH}_t + \alpha_7 \text{HDH}_t^2 + \alpha_8 \text{GS}_{t-1} \times \text{CDH}_t + \alpha_9 \text{GS}_{t-1} \times \text{HDH}_t + \varepsilon_t
\]  
(2.29)

where GS_{t-1} represents the gas storage inventory availability, while CDH and HDH are hourly average weather data for heating and cooling degree hours. As in the case of Longstaff and Wang, they estimate the empirical model using hourly real-time and hourly day-ahead forward prices from the PJM market\(^{14}\). The regression results, confirm the findings of Longstaff and Wang. In addition, they show that the availability of gas storage has an impact on the forward premium especially when demand for electricity increases and space-heating demand for gas is low.

Respectively, Botterud, Kristiansen and Ilic (2009) argue that the concepts of convenience yield and storage costs should be relevant in a hydro dominated power market. For that purpose, they examine the relationship between spot and weekly futures contracts in the NordPool market, where the share of hydropower in total supply is particularly high. By comparing the convenience yield accruing from the spot and futures electricity prices, i.e.:

\[
\text{Convenience yield}_t = \ln \left( \frac{\text{Average weekly electricity spot price}}{\text{Futures electricity price}} \right)
\]  
(2.30)

and hydro storage data, they find that the former is on average negative, indicating that spot prices tend to be lower than the futures prices. Moreover, they detect a seasonal pattern, according to which the convenience yield on power futures contracts tends to be positive in winter when hydro capacity is low, whereas it becomes negative during the summer when hydro reservoirs are filled. In addition, estimation of the risk premium indicates significantly higher futures prices relative to the realized spot prices.

On the other hand, Routledge, Seppi and Spatt (2001) consider a cross commodity model in order to study the effect of physical storage and conversion options on spot and derivative prices of commodities. For that reason, they assume an economy with electricity and storable potential fuels such as natural gas and oil. They conclude that a storage-conversion equilibrium exists, when the price distribution is skewed with higher volatility. Additionally, the correlation between electricity and fuel prices (e.g., oil and natural gas) is not constant but depends on demand and the level of inventory as well.

\(^{14}\) Thus the premium is estimated as the difference between forward day ahead and real time prices for each of the 24 hours of the day, while the variance and skewness measures are estimated on the real time prices.  
\(^{15}\) Botterud et al derive the specific measure of the convenience yield on the assumption of a zero interest rate, which they consider as a reasonable assumption for the relatively short holding periods of one to six weeks used in their analysis.
Furio and Meneu (2010) examine the ex-post and the ex-ante relationship between forward and expected spot prices in the Spanish electricity market. The ex-ante premium is defined as the difference between the forward price and the expected spot price.:

\[ F_{t,T} = \text{Risk premium}_{t,T} + E_t \left( S_t \right) \]  

(2.31)

whereas the ex post or realized premium denotes the difference between the forward price and the realized spot price at the day of delivery:

\[ F_{t,T} = \text{Risk premium}_{t,T} + S_t \]  

(2.32)

In the ex post case, the partition of the data set in two sub-samples indicates the existence of a positive and a negative estimate respectively of the forward premium, which is statistically significant for both samples. Furthermore, they find that the forward premium is affected by variations in hydro-capacity and the demand for power, whereas they partially testify the Bessembinder and Lemmon model. As far as the ex ante forward premium is concerned, forecasts of future spot prices are based on information about demand and supply of power. The specific prices accruing from a GARCH (1,1) process indicating similar results as the ex post forward premium case.

Lucia and Torro (2008) empirically analyze the behaviour of the risk premium in futures contracts traded at the Nord Pool market. The results confirm the existence of positive, on average risk premiums, even though considerable variation is observed within the year. Larger positive premiums are recorded during winter, whereas zero risk premiums are found in spring and summer. This finding is consistent with the proposition of Bessembinder and Lemmon (2002) that positive skewness in the distribution of spot prices should be observed when fluctuations in demand are more usual. They also suggest that variation in the electricity risk premium can be explained by the supply side of the power market, in particular the level of hydro reserves.

Cartea and Villaplana (2008) focus on the behaviour of spot and futures electricity prices with respect to power demand and capacity. Demand for electricity, is modelled in order to capture the seasonal patterns and the mean reversion, whereas capacity to represent the level of energy that can be produced in different months of the year. Their model indicates that the premium tends to be higher for contracts that mature during periods of higher demand for electricity, whilst negative values of the premium are observed when demand for power exhibits smaller fluctuations.
2.9 Conclusions

The power industry has attracted the researchers’ interest during the last decades, as the deregulation process has been set forward. Many studies focus on the restructure procedure that took place in the British and the US markets in an attempt to examine, whether competitiveness and efficiency -the underpinning reasons of the reform, have been implemented.

Moreover, the non-storable nature of electricity implies that potential shocks in demand or supply side require time in order to wipe away. Due to that characteristic, a significant number of studies examine the distribution of electricity prices, mainly excess kurtosis and skewness, mean reversion and upward movements of short duration. The mean reverting property implies that both prices and demand for power as well exhibit significant volatility.

On the other hand, competition in specific segments of the electricity supply chain has raised issues concerning the market design and the risk management. Deregulation has followed the introduction of power derivatives in major exchange markets (NYMEX, EEX, NordPool) providing a wide range of trading tools. The main approaches in the pricing of futures contracts are the normal backwardation theory suggested by Keynes and the cost-of-carry or storage theory developed by Kaldor, Working, Brennan and Telser.

The theory of normal backwardation is based on equilibrium considerations and postulates that hedgers will be willing to pay a risk premium in order to hedge their production from unanticipated price movements. This premium, which represents the difference between the futures and the expected spot price, represents the compensation of speculators for the risk that they are willing to undertake. In contrast to the theory of normal backwardation, the storage theory suggests that inter-temporal price differences reflect the costs of carrying the commodity, i.e., warehousing, insurance and financing costs within a specified time period. A critical issue in the theory is the introduction of the notion of the convenience yield, which represents the benefit that accrues to the holder of the commodity.

As far as the electricity futures market is concerned, the fundamental view suggests that the cost-of-carry theory is not applicable, since the no-arbitrage argument does not hold. This happens because an investor cannot take a position in the underlying market and hold it until the date of the contract’s expiration. This view has considerably influenced the research on power derivatives and due to that reason many studies focus on the relationship between the futures and the expected spot electricity prices. Among those is the study of Bessembinder and Lemmon, who demonstrate that the risk premium in the futures power market is related to the variance and the skewness of the wholesale electricity price. Many empirical studies, find evidence in favor of that proposition. On the other hand, research has also focused on the relationship between power futures prices and the price of the fuel or the demand for electricity. The most well known are the studies of Douglas and Popova (2008) who propose
that the level of gas inventory is a significant determinant of the premium in electricity markets, whereas Ilic et al. (2009) presume that the cost of carry theory is applicable in those markets with high shares of hydro power generation. According to that perspective, our study aims to enhance the view that the indirect storage of electricity gives can be supportive of the cost-of-carry implications in the pricing of electricity futures prices.


### Chapter 3: Theoretical part

#### 3.1 Introduction

This section introduces the methodological approach with respect to the proposition of an indirect type of storage in the power industry through the fuel(s) used in the generation process. The concept of convenience yield from the fuel’s perspective is a key determinant to the proposed relationship given that the markets of energy resources and the power industry are interrelated.

![Figure 3.1: Determinants of spot electricity price](image)

To accomplish our proposition the following assumptions should be made:

- The demand for electricity varies on a daily basis, enabling somebody to distinguish the peak from the off-peak cases,
- The supply side adjusts to the demand for electricity and the pricing of spot prices is based on the merit order dispatch,
- A competitive wholesale electricity market is considered, in which prices are subject to variation, in contrast to the retail power market where prices are usually regulated and relatively fixed,
- A futures power market exists, in which market participants in the power sector can participate and
- The fuel used in power generation is storable, whereas a conversion process exists that transforms a specific type of energy (e.g. mechanic) into electricity.
3.2 The demand for electricity and the supply side adjustment

The demand for electricity exhibits seasonal fluctuations related to weather conditions and economic activity. In some regions shifts in demand during the winter are related to heating needs, whereas in other areas demand peaks are mainly recorded in summer due to the extensive use of air-conditioning. Moreover, electricity demand varies according to time and increases during the weekdays’ working hours, while it decreases during the night and weekends when both industrial and residential consumption is lower.

Given that electricity is non-storable, the power industry operates under specified rules in order the supply side to be matched with demand in real time. According to the level of load\textsuperscript{16}, different types of power plants are set in operation in order to supply and secure a constant flow of power. Those plants are distinguished between base, intermediate and peak load units. Base load units produce electricity at a constant rate and for that reason less expensive fuels (subsequently operating costs are lower) are used in the generation process. In contrast, intermediate and peak load plants are used interchangeably to provide additional power in the system when demand for electricity is higher.

**Figure 3.2: An example of the indirect relationship between power generation and fuel inventory**

The allocation of power units according to the level of demand implies that a potential amount of energy is indirectly storable through the amount of fuel used in the power production. Figure 3.2 is used as a simple example to express the rationale of the preceding assumption. Even though inventories of electricity are not available, power producers can accumulate fuel that in turn will be used in the generation process when additional demand for power is required.

\textsuperscript{16} The term (electrical) load describes the quantity of electricity consumed at any particular point in time.
3.3. The merit order schedule

The establishment of competitive wholesale electricity markets aims to increase the industry’s efficiency by promoting fuel diversification and lower prices for end consumers. Competitive electricity markets have been designed upon the principle that prices should be determined (reflect) by the marginal cost of production in order for all resources to be efficiently allocated.

Figure 3.3: The merit order ranking in the power sector

For that purpose producers on a regular basis provide sale offers to the system operator indicating the minimum price for which they would agree to operate for specific hours during the day. The system operator ranks those offers, in ascending order, and sets the market price at the corresponding level of demand. At the intersection point of demand and supply curves the equilibrium consumption and price of electricity (known as the market clearing price) emerge. All units that submit offers below the equilibrium price are requested to operate and receive a uniform price, which is the price per MW of electricity charged by the power unit that submits the highest accepted offer. According to the economics of competitive markets, if a sufficient amount of producers participate in the power industry then the market price determined by that rule should reflect the industry’s marginal cost of production.

Figure 3.3 shows an example of the supply curve in wholesale power markets, known as the merit\(^\text{17}\) order process. The sale offers with smaller marginal costs enter the supply curve at the lowest level followed by power plants with higher marginal costs of production. The must-run units labeled on the graph describe the generation facilities necessary to maintain the security of the power system.

\(^{17}\) Generators are “in merit” when their offers are accepted by the system operator and “out of merit” when they are unaccepted.
Chapter 3: Theoretical part

The collection of offers in a pool market and the determination of the market clearing price with a dispatch rule reflects the optimal use of available energy resources compared with other less efficient procedures, such as the payment of the asking price for each producer. In case pay-as-bid schemes were adopted, generators could be discouraged from submitting offers reflecting the marginal cost of their production. Instead, they might have the incentive to conjecture the range of the clearing price, bidding subsequently the level they would anticipate to collect the maximum possible revenues. In this occasion, generators – usually power plants with less expensive energy resources, could run the risk of remaining out of the schedule as a result of overestimating the value of the market clearing price. So therefore, the market clearing price would be technically driven to higher than normal levels, which is the exactly opposite result than that at which deregulation in wholesale power markets aims.

Figure 3.4: Average daily electricity spot prices in the Dutch power market

On the other hand, the merit order dispatch can explain the presence of price jumps like those illustrated in Figure 3.4 with respect to daily spot prices from the Dutch power market. Sharp upward price movements, which are shortly followed by drops of the same magnitude are attributed to the non-storable nature of power and the dependence on real time demand and supply conditions. In contrast, in the case of storable commodities prices are not only determined by existing supply and current demand, but by the level of inventories as well. For instance, in a storable commodity the market price tends to be lower when large supplies from a previous production process have been accumulated.

In the power industry, however, lower elasticity of supply associated with the inability to adjust inventories imply that small changes in demand can put upward pressures in market clearing prices. Figure 3.5 shows that if an increase in (inelastic) demand takes place, the corresponding demand curve will reach a new intersection point, in which the supply curve

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becomes near vertical indicating that power plants with higher marginal costs will be dispatched by the system operator to provide power to the grid.

**Figure 3.5: Explanation of electricity price spike upon demand and supply dynamics**

As production approaches its capacity limits, small changes in demand for power give rise to changes of significant magnitude in the spot price (a small change from Q₁ to Q₂ on the horizontal axis leads to a disproportional increase in prices from P₁ to P₂). However, as the demand shock diminishes, the demand curve shifts to the left and the price of electricity returns to a lower level.

### 3.4 Long and short positions in spot and futures electricity markets

Restructuring in the power industry has removed price controls and at the same time has encouraged market entry. However, fluctuations in wholesale prices have led to increasing uncertainty, which has justified the emergence of new markets for energy-based financial products. Electricity derivative markets aim to offer opportunities to the market participants to hedge price risks and take advantage of any trading opportunities.

In the electricity industry, market participants face different types of risks related to the distribution of electricity price and its high volatility. The market consists of power generators, large firms that buy electricity to secure their production process (for instance large industries) and power retailing firms acting as intermediaries between power plants and final consumers. Both types of market participants, however, can use futures contracts to hedge from risks associated with price variation in the spot market.

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18 These firms normally require significant amount of power to run their business, thus they usually get a discount in the price that they pay.
For instance, power generators face the option of not being allocated by the system operator in case their offers are out of the merit order classification. In this case, they should encounter major outlays, known as start up costs that represent the expenses of shutting down and restarting the generation process. In order to hedge from a potential decrease in electricity price, power generators can enter the futures market by selling futures contracts on electricity. Thus, they hold long positions in the spot market and use a short hedge to avoid a potential fall in price. By entering the futures market, they undertake the obligation to deliver electricity according to the contracts specifications. Figure 3.6 illustrates interactions between the cash and the futures market faced by producers.

On the other hand, large industries and power retailers seek to eliminate the risk from unexpected upward price movements that will possible lead to additional costs. For instance, retailing firms will incur significant losses if they buy high in the wholesale market and sell afterwards at the fixed (or regulated) prices usually met in the retail market\(^{19}\). For that

---

\(^{19}\) Electricity prices offered to household consumers are usually controlled by a public authority and must be approved by the public authority before the prices can be charged to customers\(^{21}\).
purpose, they can hedge their short position in the cash market by entering the futures market in order to buy contracts for delivery of power at a specified price and date in the future. In this way any profit from entering the futures market offsets potential losses from higher electricity prices in the spot market.

The payoff of electricity futures contracts for generators and load serving firms is given by the relationship:

\[
\text{Payoff of a futures contract} = S_T - F
\]

where \( S_T \) stands for the average spot price of electricity during the month that the delivery of the commodity takes place.

### 3.5 Implications of the Cost of carry theory

Based on the assumption that electricity is non-storable, the main strand of literature in power markets consists of studies—for example Bessembinder and Lemmon (2002), Longstaff and Wang (2004), that examine the relationship between futures power markets and the principles of the normal backwardation theory. In this sense, the difference between the spot electricity price expected in the future (date that power delivery takes place) and the futures price they pay to obtain the electricity futures contract, represents the risk premium on the futures’ contract or the investor’s reward for the undertaken risk:

\[
F_{t,T} - \text{Risk premium}_{t,T} = E_t[ S_T^{\text{Electricity}} ]
\]

where \( F_{t,T} \) represents the futures prices at time \( t \) for delivery of electricity at time \( T \), Risk premium\(_{t,T}\) is the compensation required for the undertaken risk and \( E_t[ S_T ] \) is the spot price expected to prevail at the date of delivery \( T \).

However, based on the argument that electricity is indirectly stored though the fuel used in generation process, we examine whether the assumptions of the cost-of-carry theory are applicable to the pricing of futures power contracts. For instance, the role of natural gas inventories in the determination of a premium in electricity futures markets is examined by Douglas and Popova (2008), who empirically test the effect of gas storage constraints on the higher moments (i.e., variance and skewness) of electricity price distribution. Their findings, suggest that electricity prices are affected by gas inventory when demand for electricity increases:

“«....The Bessembinder and Lemmon model does not address the question of what factors cause the variance and skewness of the anticipated distribution of the spot price to vary, but both common sense and the literature give ample reason to believe that the moments of the electricity price distribution are affected by the availability of gas storage...[Douglas and Popova, page 1716]».”
Similarly to Douglas and Popova, Routledge et al. propose that prices of storable fuels affect the price distribution of electricity through arbitrage and conversion opportunities. In this context, we argue that the level of inventory in the fuel market and the potential impact of the latter on electricity prices can be approached through the concept of the convenience yield introduced in the cost-of-carry theory.

The implication of the convenience yield, or the benefit that accrues to the holder of a physical commodity but not to the owner of a futures contract, is the inverse relationship, at least in a theoretical point of view, to the level of inventory.

**Figure 3.8: Theory of storage – The relationship between convenience yield and the level of inventory**

Therefore, the value of the marginal convenience yield declines as the aggregate level of inventory increases, while it rises when stocks become small. Pindyck (1994) suggests that the relationship between the level of inventory and convenience yield is convex implying that it rises rapidly as inventories diminish and remain close to zero as long as stocks are moderate to high. At high levels of stocks, marginal storage becomes increasingly expensive as storage facilities reach full capacity levels and the marginal benefit from adding stocks becomes zero. This inverse relationship therefore, allows us to use the convenience yield as a proxy of inventory in our proposition.

According to that view, it is argued that even though electricity is non-storable, a “hidden” yield exists, which is related to the availability (storage) of the input fuel, while it has an impact on the distribution of electricity prices. In the study of Douglas and Popova for instance, that perception should be related to higher estimates of convenience due to lower inventory levels in the natural gas storage market.
Moreover, the theory of storage postulates that inter-temporal price relationships\textsuperscript{20} are determined by the net costs of carrying the commodity within a specified time interval. The most common implication is the estimation of the basis defined as the difference between the futures price and the contemporaneous spot price:

\[ \text{Basis}_t = F_{t,T} - S_t = S_t r_i + SC_{t,T} - Z_{t,T} \]  

(3.3)

The preceding relationship shows that the basis or the price (spread) of storage as it is also referred to, can become either positive or negative according to the combined level of carrying costs and the convenience yield, hence the following cases can be distinguished:

**Case 1:** \( F_{t,T} > S_t \) or a positive basis \((B_t > 0)\) observed when inventories are high. In that case convenience yield is lower than the sum of interest rate and warehousing costs and subsequently the futures price at time \( t \) is higher than the spot price.

**Case 2:** \( F_{t,T} < S_t \) and the basis becomes negative \((B_t < 0)\). It should be observed at lower levels of commodity’s inventory in which case the convenience yield will be higher than carrying costs and subsequently the spread between futures and spot prices is negative.

At the date the contract expires, the basis should be zero and the futures price equal to the spot price \((F_t = S_t)\). If this is not the case, then arbitrage opportunities will emerge and lead the two prices to converge either when physical delivery of the commodity takes place or when the futures position is financially settled. In the case where delivery takes place, investors with outstanding short positions (the shorts) deliver the commodity and investors with outstanding long positions (the longs) should accept it. If at that date the spot price \((S)\) is higher than the futures price \((F)\), the longs will accept delivery and make a risk-less profit by selling the commodity at the spot market. As the number of investors who enter in this transaction increase, the spot price will start to decline approaching the futures price. Likewise, if \( F > S \) at expiration, the shorts will profit from buying cheaper at the spot market and deliver the product at the higher futures price. In this way they will cause \( S \) to increase and finally lead the spot price to equal \( F \).

Contrariwise, if futures contracts are financially settled the following schemes can be considered. If \( S > F \) the shorts will offset their initial position by buying futures contracts (close their position in the futures market by entering the opposite to the initial position). The demand for futures contracts will raise \( F \) and as a result the two prices will drive closer to each other. In contrast, if at expiration \( F > S \) the longs will financially settle their initial position

\textsuperscript{20} Working defined inter-temporal price relationships as the difference at a given time between prices applicable to different periods like for instance a spot and a forward price on the same commodity or the relation between two forward prices. He did not refer to the relationship between price today and price at a previous date.
by selling futures contracts. The increased supply of futures contracts will cause $F$ to decrease to the level of $S$.

### 3.6 Price relationship between electricity and input fuel

In this section we examine the pricing of electricity futures with respect to the fuels used in the power generation and the process required to convert a specific type of energy into electricity. Through the fuel’s storability we convey the implications of the cost of carry theory to the futures and spot prices of electricity. The proposition resembles to the relationship between electricity and natural gas prices in a spark spread. In our case, however, it can be extended in order to examine the impact of other fuels, beyond natural gas, in the power pricing.

Inter-commodity spreads —for instance the crack spread (crude oil and its refined products) and the crush spread (soybeans and its processed products oil and meal), combine short and long positions in different commodities in order to minimize the risk from potential price changes. As far as the spark spread is concerned it takes the form:

$$\text{Spark spread} = \text{Price of electricity - } \left[ \frac{(\text{Cost of Natural Gas}) \times \text{Heat Rate}}{(\$/MWh) \times (\$/MMBtu/\text{MWh})} \right]$$

(3.4)$^{21}$

Relationship (3.4) shows the difference between the wholesale electricity price and the cost of natural gas used in the generation process, while heat rate represents the amount of energy required to produce a unit of electricity. The price of the fuel is a critical issue, since it represents the main variable cost in power generation; hence it significantly affects the price of the end commodity (electricity). In the form of (3.4), the spark spread offers an indication of whether a power plant is worth operating. Given the prices of the two commodities the plant should generate power if only the spread is positive:

$$\text{Spark spread} > 0 \iff \text{Price of electricity} > \text{Cost of Natural Gas} \times \text{Heat Rate}$$

(3.5)

Along these lines, the first objective is to determine the assumptions according to which the relationship of the effect of fuel inventory to electricity spot and futures prices is derived. Those assumptions are related to the distinctive characteristics that electricity markets exhibit compared to other markets (production with different energy resources-technologies and regional characteristics). In particular:

**i)** Fuel cost comprises the main determinant$^{22}$ of the wholesale electricity price, mainly for traditional resources used in power production such as coal and natural gas. Therefore, the choice of energy resources should have a different impact on the plant’s operational costs and subsequently on the level of (wholesale) electricity prices.

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$^{21}$ The terms in brackets denote the unit of energy per US dollars

ii) A marginal-cost based price in the spot electricity market is determined according to the merit order rule. For that purpose, the term marginal fuel describes the energy resource used by the power plant that submits the highest accepted offer required, in order to ensure that supply matches demand. The specific plant sets the price for all the power sold at a given time.

**Figure 3.9: Determination of marginal fuel according to the level of demand**

A. The case of lower demand

B. The case of higher demand

According to that view, the fuel used by plant C is the marginal fuel in the example described on Figure 3.9A, whereas an increase in demand (case B), also requires the dispatch of plant D. The latter, implies that units A, B and C receive the price submitted by power plant D.

iii) Any type of fuel used in power generation follows a certain process, in order the amount of energy released (thermal, mechanic, etc.) to be converted into electricity. The amount of fuel required to produce electricity depends on the generator’s efficiency. The latter is summarized in the term operating heat rate (HR), which is defined as the amount of British thermal units (Btus) of the input fuel required to generate a megawatt-hour (MWh) of electricity. The lower the heat rate the more efficient the generator will be, because less amount of fuel is used for electricity production. In the literature, for instance, it is suggested that a generator operating at 100% efficiency requires approximately 3.4 million Btus (MMBtus) of natural gas to produce 1 MWh of electricity.

iv) Even though electricity markets are considered to a large extend self-sufficient relying on power produced within the market’s boundaries, interconnections aim to optimize the use of generating resources between neighbouring markets. Interconnection infrastructure can facilitate market integration and lead to lower operating costs if an efficient coordination between power units exists.

However, in order to concentrate on the effect of fuel inventory on the pricing of electricity, we assume that imports of electricity are implicitly included in the merit order dispatch. As Figure 3.10 shows, imports are treated as part of domestic power production, such as the amount of power provided by the local power units. In this perspective, imports are treated
as a must run generator\textsuperscript{23} in which case the assumption of determining the spot electricity price according to the marginal fuel in the merit order schedule is not altered.

Within this framework the proposition is tested with historical data from power markets, which are less reliant on imports\textsuperscript{24}. In this manner, it is expected that the effect from electricity imports on the results will be lower relatively to other power markets with significant cross-border trading activity. In addition, it should be also noted that the effect from cross-border exchanges of electricity is restricted by the transmission capacity of interconnectors, which is considered as relatively fixed\textsuperscript{25}.

**Figure 3.10: Imports of electricity as part of domestic supply in the merit order curve**

Moreover, in order to accomplish our proposition we assume a time interval of two periods, the present time denoted as \( t \) and a future date \( T \), in order to examine the determinants of power prices within that period. Considering the previous assumptions we argue that the price of electricity at time \( (t) \) should be determined by the level of demand for power, i.e.,:

\[
S_i^{\text{Electricity}} = f(\text{load}_i)
\]  

(3.6)

Even though \( S_i^{\text{Electricity}} \) depends also on the maximum amount of power the grid transmits, equation 3.6 implies that wholesale electricity prices fluctuate with demand. Therefore, given the availability of units in the merit order dispatch, the cost of power production will change according to its level. Based on assumptions i to iv, the price of electricity should reflect:

a) the cost of the marginal fuel in power generation that also incorporates start-up expenses proportional, by assumption, to the amount of fuel used and

\textsuperscript{23} The assumption is made by London Economics in a study with respect to the structure and performance of wholesale electricity markets\textsuperscript{[41]}

\textsuperscript{24} See Section 4.2, page 80.

\textsuperscript{25} Allocation of power cannot exceed a certain limit determined by the physical capacity of the transmission lines. In case demand exceeds capabilities of transmission then the market is in congestion. This is a fundamental difference between electricity and other commodities where their imports or exports do not face major barriers in their flow.
b) a yield accruing from the production process (in particular the conversion of the fuel’s energy into electricity) denoted as the “conversion yield”. This yield describes the return that power generators earn; a fixed operating surplus from the activity.

Under those presumptions the spot electricity price at time (t) can be written as:

\[
S^\text{Electricity}_t = HR \times S^\text{Marginal Fuel}_t + c \times HR \times S^\text{Marginal Fuel}_t + K_t = (1 + c) \times (HR \times S^\text{Marginal Fuel}_t) + K_t
\]

\[
S^\text{Electricity}_t = b \times HR \times S^\text{Marginal Fuel}_t + K_t, \text{ where } b = 1 + c \] (3.7)

In equation (3.7) the term HR denotes the heat rate or the amount of fuel incorporated in power production, \( S^\text{Marginal Fuel}_t \) is the spot price of the marginal fuel and \( K \) the conversion yield.

For the purpose of the study the conversion yield is regarded as constant (i.e., \( K_t = K \)) given that the time interval between \( t \) and \( T \) is not very distant\(^{26}\). Respectively, the product \( HR \times S^\text{Marginal Fuel}_t \) expresses the generation cost and \( c \times HR \times S^\text{Marginal Fuel}_t \) the proportional startup expenses. According to (3.7) the spot price of electricity reflects the variable (or operating) costs of generation and the yield from the conversion process.

Based on the preceding view, the price of electricity expected at a future date \( T \) will be determined by the level of demand of power and the market price of the fuel on the specific date. Subsequently, on a forward looking perspective equation (3.7) should reflect the expectation of the prices between the two commodities, which means:

\[
E_t\left[ S^\text{Electricity}_t \right] = b \times HR \times E_t\left[ S^\text{Marginal Fuel}_t \right] + K_T \] (3.8)

where \( E_t \) denotes the expectation of future spot price on date \( t \). In (3.8) the heat rate and the conversion yield are assumed fixed and for that reason expectations are not considered.

In addition, expectations on market conditions at a future date can be formed by futures trading or likewise by the sale and purchase of contracts for commodities’ delivery at a future date. Under this perspective equation (3.8) describes the price spread between the futures prices of electricity (\( F^\text{Electricity}_{t,T} \)) and the marginal fuel in power generation (\( F^\text{Marginal Fuel}_{t,T} \)) and it can be rewritten as:

\[
F^\text{Electricity}_{t,T} = (b \times HR \times F^\text{Marginal Fuel}_{t,T}) + K_t \] (3.9)

Therefore, power generators, large industries and distributors are aware that the price at which they sell or buy electricity in the future will be determined, at a significant level, by the fuel’s price. Since demand for electricity is to a certain extend predictable, due to the seasonality it exhibits, it can indicate the fuel that corresponds to the level of the supply curve for which its price should be determined. Power futures markets on the other hand,

\(^{26}\) In the empirical study of the proposition the higher maturity of futures contracts are of 12 month duration.
enable participants to take positions and hedge against the uncertainty caused by future price movements.

Moreover, the storable nature of the fuels used in electricity production is a critical characteristic in the assumed methodology. Coal and oil for instance, can be stored in large silos, water (hydro power) is reserved in large dams, whereas natural gas can be liquefied and injected in storage reservoirs. By the time inventories of these fuels can be carried within time periods, the implications of the theory of storage are applicable on their pricing, meaning that the futures price of the marginal fuel should be determined by the well known expression:

\[
F_{t,T}^{\text{Marginal Fuel}} = S_t^{\text{Marginal Fuel}}(1 + r_f) + SC_t^{\text{Marginal Fuel}} - Z_{t,T}^{\text{Marginal Fuel}}
\]  

(3.10)

where \(S_t^{\text{Marginal Fuel}}(1 + r_f)\) is the marginal’s fuel compounded price at date \(t\), \(SC_t^{\text{Marginal Fuel}}\) denotes the cost of storing the commodity from time \(t\) to \(T\), while \(Z_{t,T}^{\text{Marginal Fuel}}\) is the convenience yield for the same period.

Considering a power generator, then equation (3.10) implies that it should be indifferent between buying the fuel at time \(t\) and storing it until the date needed for power generation (assuming this will be date \(T\)), and the alternative of purchasing a futures contract for delivery of fuel at \(T\). According to the first option, power generator pays the price of the fuel at \(t\) and stores the commodity until the date of power generation \(T\). In this case, it incurs the costs of storing the commodity for the specific time interval. However, holding the underlying fuel may become more profitable than owning a derivative instrument, due to its relative scarcity. For instance, in the case of higher demand for electricity, additional generated power should probably be associated to higher revenues from the sale of power price that normally increases in such events. The convenience yield (or the benefit) accruing from the storage is deducted from total costs and therefore the net carrying costs of the marginal fuel should be equal to:

\[
\text{Net carrying costs}_{t,T}^{\text{Marginal Fuel}} = \text{Carrying costs}_{t,T}^{\text{Marginal Fuel}} - \text{Convenience yield}_{t,T}^{\text{Marginal Fuel}} = > \text{Net carrying costs}_{t,T}^{\text{Marginal Fuel}} = SC_{t,T}^{\text{Marginal Fuel}} - Z_{t,T}^{\text{Marginal Fuel}}
\]  

(3.11)

Consequently, fuel’s spot price and net carrying costs at \(t\) comprise the futures price for delivery at \(T\). If at that date the specific price differs from the spot price, arbitrage opportunities for riskless profit will emerge.

Using (3.9) we derive the futures price of a power contract based on conversion and fuel’s price determinants, on the assumption that electricity is indirectly stored through the fuel used in its generation process. By expanding (3.9) we obtain:
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Equation (3.12) suggests that the price of an electricity futures contract for delivery at time \( T \), should reflect the price of the marginal fuel’s price used in power generation, the net carrying costs involved in the storage of the fuel and the conversion yield, which is required to transform a certain type of energy into electricity. These costs are in relation to the efficiency of the generator’s heat rate. The more efficient the generator the less quantity of fuel will be required and subsequently, the lower the cost related to the fuel’s carrying costs. It should be also mentioned that according to (3.11) the conversion yield is not affected by the efficiency of the generator. In other words, we have assumed a fixed process in the transformation of each type of energy into electricity.

Finally, it can be examined whether the specific approximation holds in equality. For that reason consider the following two cases. If:

\[
F_{Electricity}^{t,T} > b \times HR \times \left[ S_t^{Marginal \ Fuel} (1 + r_t) + SC_{t,T}^{Marginal \ Fuel} - Z_{t,T}^{Marginal \ Fuel} \right] + K_t
\]  

then, many investors will find profitable to take short positions in electricity futures market, buy HR quantity of fuel in the spot market and store it until \( T \) at which time it is processed to produce electricity and delivered towards the short futures position. Increased demand for fuel will cause its price to rise, while the carrying costs will be higher, too, since the quantity of fuel needed from the increased number of investors that participate in the arbitrage is higher. Therefore the right hand side will be increased up to the level of the futures electricity price. On the other hand, if:

\[
F_{Electricity}^{t,T} < b \times HR \times \left[ S_t^{Marginal \ Fuel} (1 + r_t) + SC_{t,T}^{Marginal \ Fuel} - Z_{t,T}^{Marginal \ Fuel} \right] + K_t
\]  

then, investors will be interested in buying electricity futures contracts (take long positions). Lower futures price of electricity imply lower demand for power and subsequently the quantity of fuel that will be required for generation will respectively lessen. Thus, the price of the fuel and the carrying costs will decrease, making the terms of the right hand side of the preceding inequality to fall, until the two sides become equal.

3.7 The price of indirect storage (basis) of electricity

Given the objective of the study to examine the impact of fuel inventory on the spot and futures electricity prices, the main implication of (3.12) is that the basis of electricity is linearly related to the marginal fuel’ carrying costs:

\[
\text{Basis}_{Electricity}^t = HR \times b \times \left[ S_t^{Marginal \ Fuel} r_t + SC_{t,T}^{Marginal \ Fuel} - Z_{t,T}^{Marginal \ Fuel} \right]
\]  

See Appendix of Chapter 3 for the derivation
According to (3.15), the basis in electricity futures market is positively related to the generator’s efficiency (HR) and negatively related to the marginal’s fuel convenience yield. We have presumed that the interest cost has a minor role in the determination of the basis in the power market; subsequently we examine whether the level of (marginal) fuel inventory, expressed through the convenience yield \( Z_{\text{Marginal fuel}, t} \) has an impact in the relationship between electricity spot and futures prices.

For that purpose, we recall an example regarding natural gas and electricity markets and the use of the former in the power generation process. In the US it is observed that demand for natural gas increases during winter and summer months. In the winter, higher demand is related to the need of households for heating purposes and of power plants to generate electricity. Similarly, natural gas demand increases during summer when power plants operate to generate electricity to cover demand for air conditioning needs. Additionally to the rising demand during those periods, higher prices are also recorded on both commodities in the wholesale market.

In natural gas market therefore, tightness in supply because of increased demand causes the commodity’s price to increase. The specific increase, affects the price of electricity, by the time the variable cost determined by the fuel price has also risen. According to the preceding example we can distinguish among the following cases:

1. **The level of the marginal fuel's inventory is high**: As the preceding example has indicated, the supplies of storable commodities vary according to the level of consumption. Some energy commodities, such as oil and gas, are used in various activities (household needs, fuelling in the production process), while others like coal are mainly used in power generation. During periods of moderate demand it should be expected that the level of stocks will increase (for instance natural gas is injected during summer). In this occasion, the convenience yield related to the aforementioned storable commodities should be smaller, according to the theory of storage. The negative relationship between electricity basis and the level of marginal’s fuel inventory suggested by equation (3.15) indicates that in case the convenience yield reduces, the basis should increase, leading to higher futures price relatively to the contemporaneous spot price of electricity.

**Textbox 3.1: The relationship between marginal fuel’s inventory and electricity basis-The case of high inventory level**

<table>
<thead>
<tr>
<th>Marginal fuel’s inventory ↑</th>
<th>Theory of storage</th>
<th>Convenience yield ↓</th>
</tr>
</thead>
<tbody>
<tr>
<td>( F_{\text{Electricity}, t} )</td>
<td>Equation 3.15</td>
<td>( S_{t} )</td>
</tr>
</tbody>
</table>

The implication of this relationship is that if the level of supply and inventory are adequate to meet demand in the fuel’s market, then the possibility of a sudden price increase in the commodity’s spot price is less likely. Subsequently, lower fuel prices have a positive effect in
the pricing of electricity, according to the assumption that the fuel cost is the major
determinant of the wholesale electricity price.

2. The level of the marginal’ fuel inventory is low: When scarcity of supplies is
observed, inventory decreases and convenience yield increases, according to the storage
theory. As far as the energy market is concerned, the shortage in the supplies of the energy
commodities should be associated with lower inventories and higher prices in order an
uninterrupted supply of energy to be sustained.

In the case of electricity, it is implied that power generators will have to carry the burden of
increased fuel costs, leading in this way to higher wholesale power prices. Therefore, it can
be argued that a close relationship between the level of the fuel’s inventory (consequently of
the associated convenience yield) and the spot price of electricity exists. In terms of
expression (3.15) a negative basis ($F_{t,T}^{\text{Electricity}} < S_{t}^{\text{Electricity}}$ or $F_{t,T}^{\text{Electricity}} - S_{t}^{\text{Electricity}} < 0$ ) in electricity or
a lower futures price relative to the concurrent spot price may be observed when the supply
of the marginal fuel is tight, leading the power futures market in backwardation.

Textbox 3.2: The relationship between marginal fuel’s inventory and electricity
basis-The case of low inventory level

Backwardation can be even stronger, if shortages in the fuel’s supply side are associated with
substantial increase in load (for instance during either very cold or warm periods). In such
occasion, the spot electricity price may increase at a level above normal (in other words a
price jump will be recorded). Large upward price movements in the spot electricity market
associated with shortages in the majority of the power industry fuel markets have been
observed in California, for instance, during 2000 due to lower natural gas reserves in
conjunction with high temperatures. Respectively, in Greece higher wholesale electricity
prices in 2008 are related to lower levels of water reserves (hydro as inventory) in
hydroelectric power stations.

3.8 Conclusions

This chapter has introduced the proposition of an indirect storage relationship between
electricity and the fuel used in the generation process, according to the basic characteristics
of a deregulated electricity market. The spot price of electricity is determined by an economic
dispatch system, which ranks the supply offers submitted by different power generators. In
this type of arrangement, power plants that use less expensive fuels to generate power and
therefore have lower variable costs are firstly dispatched by the system operator to supply
the grid with electricity. However, according to the rules of competitive electricity markets,
power plants that supply electricity are paid a uniform price, which is determined by the offer
of the last power generator that supplies the grid. Thus, it is the marginal generator that determines the wholesale electricity price. Furthermore, the fuels used in power generation are mainly storable, implying that the cost of carry theory is applicable on its futures pricing. By the time the fuel is the intermediary commodity for the generation of electricity, it should be expected that its price will affect the price of the end commodity (electricity).

By assuming storable energy resources used in power generation we argue that fuel cost and a certain yield associated to the conversion of a specific type of energy into electricity are the main determinants of the electricity price distribution. Then, the implications from fuel storage in terms of the convenience yield (the adjusted spot-futures spread of the fuel) are examined in the relationship between the futures and the spot electricity prices. The basis is a fundamental issue in the theory of derivatives pricing, since it offers an explanation of how well the hedging of price risk is facilitated. According to the proposed hypothesis, the basis risk in electricity futures or the risk arising due to the uncertainty of the hedged position until the contract is closed out, is among other reasons affected by the supply side of the marginal fuel.

The proposed relationship contributes to the literature by employing the cost of carry theory in the valuation of electricity futures contracts. In the existing literature the dominant view suggests that by the time electricity is non-storable the theory of storage, as proposed by Kaldor (1948), Brennan (1958), Cootner (1967) and Telser (1958) is not applicable. Due to that reason, the studies on electricity markets examine primarily the existence of a risk premium in the price of the futures contract, i.e., the difference between the futures price of electricity and the spot price expected to prevail at the date that delivery of the commodity takes place.

Textbox 3.3 shows the main differences between the proposed hypotheses of this study and those adopted in the existing work (to the best of our knowledge) that incorporate the use of fuel(s) in power generation and the effect that they exert on the pricing of electricity.
Textbox 3.3: Differences between relative studies in the pricing of electricity futures and the proposed model on the assumptions-scope

<table>
<thead>
<tr>
<th>Studies in the literature of electricity futures pricing</th>
<th>Our proposed model</th>
</tr>
</thead>
<tbody>
<tr>
<td>Routledge, Seppi &amp; Spatt (2001)</td>
<td>Examine the behavior of electricity basis according to the level of storage through the convenience yield of the marginal fuel in the merit order ranking. The model is testified empirically by using prices of energy commodities traded in the USA (electricity, coal, and natural gas).</td>
</tr>
<tr>
<td>Douglas &amp; Popova (2008)</td>
<td>Test the storage effect of the marginal fuel in power generation on the futures and contemporaneous electricity prices, not on the risk premium. This is done by estimating the convenience yield of coal &amp; natural gas, not storage levels.</td>
</tr>
<tr>
<td>Povh and Fleten (2008)</td>
<td>Assume supply and demand for electricity as exogenous variables that affect Spot and futures electricity prices. Examine the role of fuel’s inventory not the cost of the fuel in the generation process.</td>
</tr>
<tr>
<td>Botterud, Kristiansen &amp; Ilic (2009)</td>
<td>Estimate the convenience yield of the marginal fuel and examine whether a negative relationship exists between the electricity basis and the level of the fuel’s inventory.</td>
</tr>
</tbody>
</table>

They consider a cross commodity model and study the effect of physical storage and conversion options on the dynamics of spot and derivative prices of commodities. They use as example an economy with non-storable electricity and storable potential fuels such as natural gas and oil. They do not empirically study their model.

They empirically test the effect of gas storage constraints on the higher moments of electricity price distribution, according to the Bessembinder and Lemmon model. Results show that forward premium is negatively affected by gas storage inventory.

They model electricity forward prices by combining fuel costs and demand/supply structure of the electricity market. Their model incorporates consumption and supply capacity, forward prices of fuels, emission allowances and imported electricity.

Derive the convenience yield of the futures and spot electricity prices and compare it to the level of hydro storage. They also examine the futures risk premium in the Nord Pool market.
Appendix

Proof of relationship 3.15

Based on (3.12) it stems that:

\[
F_{\text{Electricity}}^{t,T} = b \times HR \times \left[ S_t^{\text{Marginal Fuel}} + S_t^{\text{Marginal Fuel}} r_t + SC_{t,T}^{\text{Marginal Fuel}} - Z_{t,T}^{\text{Marginal Fuel}} \right] + K
\]

\[
F_{\text{Electricity}}^{t,T} = b \times HR \times S_t^{\text{Marginal Fuel}} + b \times HR \times \left[ S_t^{\text{Marginal Fuel}} r_t + SC_{t,T}^{\text{Marginal Fuel}} - Z_{t,T}^{\text{Marginal Fuel}} \right] + K
\]

\[
F_{\text{Electricity}}^{t,T} = b \times HR \times S_t^{\text{Marginal Fuel}} + CVY + b \times HR \times \left[ S_t^{\text{Marginal Fuel}} r_t + SC_{t,T}^{\text{Marginal Fuel}} - Z_{t,T}^{\text{Marginal Fuel}} \right]
\]

In equation (3.7) we have argued that \( (b \times HR \times S_t^{\text{Marginal Fuel}}) + K = S_t^{\text{Electricity}} \). Therefore:

\[
F_{\text{Electricity}}^{t,T} = S_t^{\text{Electricity}} + b \times HR \times \left[ S_t^{\text{Marginal Fuel}} r_t + SC_{t,T}^{\text{Marginal Fuel}} - Z_{t,T}^{\text{Marginal Fuel}} \right]
\]

\[
F_{\text{Electricity}}^{t,T} - S_t^{\text{Electricity}} = b \times HR \times \left[ S_t^{\text{Marginal Fuel}} r_t + SC_{t,T}^{\text{Marginal Fuel}} - Z_{t,T}^{\text{Marginal Fuel}} \right]
\]

But \( F_{\text{Electricity}}^{t,T} - S_t^{\text{Electricity}} \) is the basis and consequently we end up with (3.15).
Chapter 4: Data description

4.1 Introduction

This chapter outlines a preliminary statistical analysis of US energy data used for the empirical examination of the proposed inter-commodity price relationship between electricity and the fuel used in the generation process. Assuming a competitive wholesale electricity market, the marginal cost of generation required to satisfy demand will have an impact on the commodity’s wholesale price. In many electricity markets, coal and natural gas power stations have become the marginal production units during certain hours of the day. The decision to incorporate the US energy market in the empirical analysis stems from the fact that data on prices and information with respect to the fuel mix and their proportion in power generation are available either from specific agencies or from database engines.

4.2 The electricity market in the USA

Before deregulation, the wholesale electricity market in the United States was dominated by vertically integrated utilities that controlled the generation resources and the distribution system required to produce and transmit electricity. In order to facilitate competition by enabling third-party entities to enter the power market, federal regulators took steps to guarantee open access in the transmission grid and power generation.

Figure 4.1: Electric Power Markets and Interconnections* in the USA

(*): A: Western Interconnection, B: ERCOT Interconnection C: Eastern Interconnection
For that purpose, the Federal Energy Regulatory Commission (FERC) adapted measures to support the establishment of Independent System Operators, the main task of which was to design the control of operations and transmission facilities. According to the rules set by FERC, the main responsibilities of an ISO should be the independent operation of the market, the provision of open access and the maintenance of the reliability of the transmission grid within the area covered by their supervision. Deregulation resulted in the development of regional electricity markets, each covering the grid and utility operations in a specific number of states. Some of them, like the Pennsylvania-Jersey-Maryland Interconnection (PJM), are among the most well functioning electricity markets worldwide.

Additionally, a large number of trading hubs operates in the specific power markets. A trading hub is an aggregation of representative buses (a set of networks inside a power substation) that create a common point for commercial energy trading. A hub acts as a common point for contracts’ trading, irrespectively of whether physical delivery will take place or not.

The electricity industry in the United States is partitioned in ten markets and three major interconnections (Figure 4.1). The NorthWest electric power market covers the states of Washington, Oregon, Idaho, Utah, Nevada, Montana, Wyoming and part of California, while it includes Mid-Columbia (Mid-C) and California Oregon Border (COB) trading hubs. In the specific region, hydro and natural gas are considered the marginal fuels used in power generation. The generating capacity, i.e., the maximum output that generating equipments can supply, exceeds 57,000 MW with the capacity reserve approaching 17,000 MW.

The Southwest electric power market covers the states of Arizona, New Mexico, Colorado and parts of Nevada, Wyoming and South Dakota. In the specific area, one of the most active trading hubs i.e., Palo Verde and additionally Four Corners and Mead operate. Natural gas is used as the marginal fuel type in electricity generation. According to 2005 data, generating capacity exceeded 45,000 MW, while capacity reserve and reserve margin was at 8,940 MW and 24% respectively. The main characteristic of the region is the surplus of generating capacity, with much of the generation in Arizona and the Four Corners area. Transmission to the California market, usually takes place during the high load summer periods and mainly through the Palo Verde high-voltage switchyard, that links the utilities of the southwest US with those of California.

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28 The Federal Energy Regulatory Commission (FERC) is the United States federal agency with jurisdiction over interstate electricity sales, wholesale electric rates, hydroelectric licensing, natural gas pricing, and oil pipeline rates. FERC also reviews and authorizes liquefied natural gas (LNG) terminals, interstate natural gas pipelines and non-federal hydropower projects.

29 A hub is a point at which electricity may be re-routed into major transmission lines.

30 PJM website definition.

31 FERC, Electricity market oversight.
Chapter 4: Data description

The Midwest electric power market covers a larger number of states from North Dakota to Ohio, while it incorporates Cinergy, First Energy, Illinois and Michigan hubs. Coal is the main fuel used in power generation. Generating capacity in summer 2006 reached 137,230 MW, with capacity reserve at 21,025 MW. In the four Midwest ISO Hubs a single price is used for settlement, regardless of the point within the hub the transaction occurs. The Cinergy hub is the most active, since it comprises about 330 nodes on the grid, covering parts of Southwestern Ohio, Northern Kentucky, and Indiana.

The PJM Interconnection covers Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia, and Washington DC. PJM is a regional transmission organization (RTO) that coordinates the movement of wholesale electricity in all parts of the 13 states and is not an electricity generation company. It includes about 350 members and customers that physically trade power through the organized real and day-ahead market. Indicative of the liquidity that the market has developed, is the introduction of PJM futures contracts for delivery during the peak and the off-peak hours of the day since 1996 in the NYMEX.

Another considerable feature of the PJM market is the capacity of power generated within the area controlled by the transmission operator, rendering the market less dependent on imports from neighbouring markets. In 2010, for instance, PJM was a net exporter of energy in the real time power market \([73]\), whereas the amount of energy imported represented less than 18% of total power produced in the specific market (Figure 4.2).

![Figure 4.2: PJM power generation, imports and exports (in thousand, 2010)](image)

Small dependence on cross-border trading is supportive of the proposition’s assumption that imports are implicitly assumed to be part of domestic power production, in order to concentrate on the effect of fuel reserves on electricity spot and futures prices.
4.2.1 Fuel mix incorporated in US power production by market

In each of the power markets examined, a diverse mix of fuels is used in the generation process. The decision of electricity utilities on the fuel they use, depends on a number of economic, technical and environmental factors, which are, to a large extent, interrelated. In the US power market, coal has the largest share in power generation (Figure 4.3), whereas the use of natural gas has increased substantially during the last decade. This is mainly attributed to the shift from coal-fired generation to environmental friendlier energy resources and the transition to a low carbon future. In addition, power generation from natural gas is considered as a load balancing scheme, since they are able (due to the rapid response) to provide flexibility between variable renewable power generation as demand fluctuations take place.

![Figure 4.3: Electricity generation by fuel type in USA](image)

Table 4.1 illustrates the diversity of fuels used in some of the US markets mentioned above. For instance, in California an extensive use of natural gas is recorded, whereas power generation in the Midwest depends almost entirely on coal. Hydroelectric power, on the other hand, is very common in the states of the Northwest market due to the high water resources in the area.

<table>
<thead>
<tr>
<th>Resource</th>
<th>Market</th>
<th>Northwest</th>
<th>Midwest</th>
<th>Southwest</th>
<th>California</th>
<th>PJM</th>
</tr>
</thead>
<tbody>
<tr>
<td>Coal</td>
<td>27.4%</td>
<td>90.4%</td>
<td>51.6%</td>
<td>1.1%</td>
<td>49.3%</td>
<td></td>
</tr>
<tr>
<td>Oil</td>
<td>0.2%</td>
<td>1.1%</td>
<td>0.1%</td>
<td>1.1%</td>
<td>0.4%</td>
<td></td>
</tr>
<tr>
<td>Natural Gas</td>
<td>19.8%</td>
<td>2.6%</td>
<td>29.6%</td>
<td>54.9%</td>
<td>11.7%</td>
<td></td>
</tr>
<tr>
<td>Hydroelectric</td>
<td>46.5%</td>
<td>0.7%</td>
<td>4.2%</td>
<td>13.0%</td>
<td>2.0%</td>
<td></td>
</tr>
<tr>
<td>Nuclear</td>
<td>5.5%</td>
<td>4.1%</td>
<td>13.2%</td>
<td>17.0%</td>
<td>34.6%</td>
<td></td>
</tr>
<tr>
<td>Other</td>
<td>0.6%</td>
<td>1.2%</td>
<td>1.4%</td>
<td>12.8%</td>
<td>2.0%</td>
<td></td>
</tr>
<tr>
<td>Total</td>
<td>100.0%</td>
<td>100.0%</td>
<td>100.0%</td>
<td>100.0%</td>
<td>100.0%</td>
<td></td>
</tr>
</tbody>
</table>

Source: EIA
Therefore, fuel diversification has an economic impact, mainly on a regional basis for each power market. Moreover, the impact of different type of fuels in the pricing of electricity is depicted in the variation that electricity prices record in different trading points.

**Figure 4.4: Annual average on peak electricity prices in major US trading hubs**

For instance, peak electricity prices are lower in regions in which coal is the dominant resource of power generation — e.g. Cinergy and Mid-Columbia, compared to regions where extensive use of natural gas takes place — for instance the PJM, California and Palo Verde markets (Figure 4.4). This observation is supportive of the argument that fuel cost is a major determinant of the wholesale electricity price in competitive markets.

### 4.3 Data description

This section reviews the main statistical properties of the power prices encountered in the empirical tests of the proposition. Those prices refer to the PJM Interconnection and the Palo Verde trading hub for which data were available (for a representative time period) both for the spot and the futures markets during the peak hours of the day.

As far as the spot price is concerned, data obtained from DataStream International are based on Dow Jones Electricity day-ahead average price indices, measured in US dollars per MWh. Electricity markets are organized on the basis of a day-ahead schedule by the time the system operator requires advanced notice to schedule the supply of electricity. Respectively, futures prices for delivery of electricity refer to a trading unit of 40 MWh per week day (or peak days as Mondays to Fridays are considered). According to the number of week days in a month (between 19 and 23) the quantity of electricity will vary between 760 MWh (i.e., $40\text{MWh} \times 19 \text{ days}$) and 920 MWh (i.e., $40\text{MWh} \times 23 \text{ days}$).
Chapter 4: Data description

Taking into consideration that natural gas power stations provide power to the electrical grid mainly during the peak load, the specific energy resource is considered in our analysis as the marginal fuel, according to the assumption of a marginal cost based spot price (assumption ii, in Section 3.6). For that purpose, the properties of spot and futures natural gas prices are also examined.

Natural gas prices for delivery at the Henry Hub, Louisiana trading point are used as reference prices because the market is the most liquid hub in the U.S. for wholesale natural gas. Henry Hub futures contracts were initiated by NYMEX on April 1990. Each contract refers to the delivery of 10,000 MBtu, while there are 36 contracts, one for delivery in each of the next 36 calendar months. However, the most actively traded are the contracts close to maturity. Trading for Henry Hub futures contracts terminates three business days before the first day of the delivery month.

Respectively, in the case of the off-peak electricity prices we focus on power markets in which coal-fired plants represent the major part of power supply. Prices from the Central Appalachia region are used, since almost 1/3 of total coal production in the USA is produced at the region. It should be mentioned, however, that due to lack of data regarding the spot market, futures prices on nearby contracts (i.e. contracts with the closest settlement date) have been used as a measure of the spot price. The Central Appalachia coal futures are traded at the NYMEX with each contract’s trading unit referring to the delivery of 1550 tons.

4.4 PJM spot and futures prices

The average PJM price during the peak hours of the day between January 2003 and December 2009 approached $64 per MWh. At the same time significant price fluctuation took place since the standard deviation estimate approximated the $24 per MWh. Prices tend to be higher during the summer period and especially in August, whereas during 2009 fell at a level lower than the respective of 2008, due to the decline of the energy consumption as a result of the economic downturn.

Positive skewness, which has been extensively recorded in the literature of electricity markets, is also evident in the data. Skewness is a measure of the degree of asymmetry of a distribution around its mean. A zero value indicates that prices are symmetrically distributed on both sides of the mean, while a negative skewness is an indication that the tail on the left side of the probability density function is longer than the right side. Respectively, a positive value of skewness, as in the case of the PJM spot prices (Figure 4.5) indicates that the majority of the prices are lower than the mean level.

32 The specific practice is usually employed – for instance Fama and French (1987) – in the absence of spot price data.
High kurtosis is also a common characteristic of electricity prices. Kurtosis is a measure of the "peakedness" of the distribution, with excess values indicating that the higher variance in the data is mainly due to the infrequent extreme deviations from the mean level. In the case of the PJM prices, the value of the specific measure is almost four times higher than the corresponding value of the normal distribution (kurtosis=3).

It is indicative that the price outliers recorded in the data set are at least two standard deviations higher than the average price, whereas in some occasions the price jumps are substantially higher. For instance, in June 2008 the average price reached $257 per MWh, a level which is eight standard deviations higher than the mean price for the specific time period.
Futures electricity prices on the other hand, for delivery in the Western hub of the PJM Interconnection in one (monthly futures), three, six and twelve months to maturity respectively, exhibit less pronounced characteristics. Futures markets provide trading tools that aim to mitigate the price uncertainty. This is a primary reason that power derivatives in major exchange markets have been introduced after the deregulation of electricity markets. Table 4.2 shows that futures prices tend to be justified by the specific proposition since they disclose less variation, expressed by the measures of the standard deviation and the coefficient of variation as well, whereas the range in which the prices are dispersed (i.e., the difference between the minimum and the maximum values) is lower than the spot prices.

Figure 4.6 depicts the different patterns of the prices of futures contracts for delivery in the specific market within different months of maturity. Futures contracts for one month and three months to delivery (1-pos and 3-pos series) exhibit higher price variability. In both cases the deviation from the mean approaches $20 per MWh, whereas the lowest volatility is recorded in annual futures (12-pos series) at $17 per MWh. The maximum futures price ($154.3 per MWh at the end of June 2008) is on the 3-pos series, whereas the minimum ($34.1 per MWh at the end of September 2006) on the monthly futures contracts (1-pos).

For the empirical analysis, we refer for each maturity of the futures contracts (i.e., one, three, six and twelve months to maturity) with the abbreviation 1-pos, 3-pos, 6-pos and 12-pos, which indicates the positions (the abbreviation pos is used for that reason) to the expiry of the contracts that were currently active in relation to the date of trading.

This evidence is consistent with the “time to maturity” hypothesis of Samuelson, where price volatility increases as time to maturity nears. Among others see Samuelson (1965) and Milonas (1986).
Figure 4.6 also demonstrates the increase of PJM futures prices from March to August 2008, when oil and natural gas prices had increased significantly. Between July and August 2008, when Brent crude oil was traded above $130 per barrel and Henry Hub natural gas prices approached $12 per MBtu, PJM futures recorded substantially higher prices. Furthermore, the sharp decrease in oil prices that took place after September 2008 had a respective influence on PJM prices, an effect which underlines the impact of fuels’ prices on the pricing of electricity.

Finally, both the spot and the futures PJM prices exhibit serial correlation. According to the Ljung-Box statistics\(^{35}\), the null hypothesis of no autocorrelation on the specific data set is rejected, implying that electricity prices are clustered, i.e., high values tend to be followed by increased values of the same magnitude and vice versa.

### 4.5 The Palo Verde spot and futures electricity prices

In the case of the Palo Verde electricity hub, the distribution of the spot prices during the peak hours of the day exhibits similar characteristics to the PJM case, i.e., positive skewness and leptokurtosis, even though the tails of the distribution are more pronounced. Fat tails in the distribution imply a higher probability of extreme values than a normally distributed variable, whereas leptokurtic distributions indicate the concentration of values near the mean level.

The mean Palo Verde spot price (for the respective data set) approximates $58 per MWh, which is lower by $6 per MWh compared to the PJM peak prices. The spot price varies between $24 per MWh to $305 per MWh with a standard deviation of $21 per MWh. Such a high estimate of the standard deviation – almost 1/3 of the mean level, implies the presence of extreme values especially during the summer period.

On the other hand, the prices of the futures contracts for delivery of electricity during the peak hours of the day at the Palo Verde hub, disclose less acute characteristics in relation to the spot case. The mean value of the monthly futures contracts is higher than the spot price, while the distribution has smaller estimates of skewness and kurtosis as well. This can be also inferred from the value of the coefficient of variation, which is lower relatively to the estimate of the spot price, whereas it falls as the holding period increases.

\[^{35}\] The Ljung-Box statistic is mainly used to examine the hypothesis that the error term of a regression is a white noise. By calculating the first \(k\) autocorrelations of the residuals, if the null hypothesis of no autocorrelation i.e.,

\[ H_0 : \rho_1 = \rho_2 = \ldots = \rho_k = 0 \]

is true, then the statistic

\[ Q^{LB} = T(T + 2)\sum_{i=1}^{k}\frac{r_i^2}{T-k} \]

follows the \(\chi^2\) distribution with \(k\) degrees of freedom. If \(Q^{LB} < \chi^2_{df,\alpha}\), then the null is accepted at a level of significance \(\alpha\).
Therefore, the main difference between spot and futures electricity prices concentrates on the magnitude of variation. Higher volatility in the spot price relates to the conditions prevailing in the real time market where the electric system can be subject to unusually high demand (mainly due to unfavourable weather conditions) or an unexpected disruption in the supply side. Those events that can lead to instantaneous imbalances between demand and supply are further exacerbated by the lack of power inventories.

Table 4.3: Summary statistics of the Palo Verde spot and futures peak prices, Jan. 2003-May 2009 (USD per MWh)

<table>
<thead>
<tr>
<th></th>
<th>Spot</th>
<th>1-pos</th>
<th>3-pos</th>
<th>6-pos</th>
<th>12-pos*</th>
</tr>
</thead>
<tbody>
<tr>
<td>Mean</td>
<td>58.1</td>
<td>73.7</td>
<td>75.3</td>
<td>70.8</td>
<td>71.7</td>
</tr>
<tr>
<td>Coef. of Var.</td>
<td>35.5%</td>
<td>31.6%</td>
<td>23.1%</td>
<td>18.6%</td>
<td>20.2%</td>
</tr>
<tr>
<td>Min.</td>
<td>24.2</td>
<td>37.3</td>
<td>44.3</td>
<td>50.5</td>
<td>52.5</td>
</tr>
<tr>
<td>Max.</td>
<td>304.6</td>
<td>148.8</td>
<td>118.3</td>
<td>111.9</td>
<td>108.5</td>
</tr>
<tr>
<td>Median</td>
<td>54.5</td>
<td>71.8</td>
<td>72.4</td>
<td>69.1</td>
<td>69.6</td>
</tr>
<tr>
<td>St. Deviation</td>
<td>20.6</td>
<td>23.3</td>
<td>17.4</td>
<td>13.2</td>
<td>14.5</td>
</tr>
<tr>
<td>Skewness</td>
<td>3.3</td>
<td>1.0</td>
<td>0.4</td>
<td>1.0</td>
<td>0.7</td>
</tr>
<tr>
<td>Kurtosis</td>
<td>31.3</td>
<td>3.7</td>
<td>2.5</td>
<td>4.2</td>
<td>2.8</td>
</tr>
<tr>
<td>Ljung-Box (1)</td>
<td>1343.3</td>
<td>1038.5</td>
<td>988.1</td>
<td>550.9</td>
<td>429.6</td>
</tr>
<tr>
<td>Ljung-Box (2)</td>
<td>2375.8</td>
<td>2067.0</td>
<td>1958.1</td>
<td>1085.0</td>
<td>849.6</td>
</tr>
<tr>
<td>Ljung-Box (3)</td>
<td>3257.8</td>
<td>3084.7</td>
<td>2909.4</td>
<td>1599.8</td>
<td>1259.4</td>
</tr>
<tr>
<td>Jarque-Bera</td>
<td>59902.3</td>
<td>193.4</td>
<td>44.8</td>
<td>127.83</td>
<td>38.1</td>
</tr>
<tr>
<td>Observations</td>
<td>1692</td>
<td>1045</td>
<td>1003</td>
<td>563</td>
<td>436</td>
</tr>
</tbody>
</table>

(*) 1, 3, 6 and 12 pos (-itions) denote 1, 3, 6 and 12 months to delivery of the futures contract.

In contrast, demand and supply shocks in the spot (or the real time) market have a lower impact in the price determination of electricity futures contracts. Instead, the price of futures contracts is determined according to forecasts on the conditions at the date of maturity. As it is underlined by the IEA the complexity of electricity spot transactions is restrictive for the determination of futures prices. Finally, the Ljung-Box statistic for up to 3 lags indicates the...
presence of autocorrelation in the data since the critical values (3.1, 5.1 and 6.8 respectively) are significantly lower than the estimated statistics; hence the null of no autocorrelation is rejected.

4.6 The Henry Hub natural gas prices

For the time period between January 2003 and May 2009 the Henry Hub spot price exhibits an average value of $6.8 per MBtus with a volatility of approximately $2.3 per MBtus.

Figure 4.8: Empirical distribution of the Henry Hub natural gas spot prices

Natural gas spot prices exhibit variation throughout the year with peaks during winter, especially January and February and summer, which are however of lower magnitude. The specific behavior is the result of the changing demand for natural gas, since in winter the needs for space heating increase, whereas demand in summer mainly originates from the higher supplies absorbed by the electricity industry. For the time period examined, the Henry hub natural gas prices show different patterns indicating that several factors influence the price dynamics during the period considered. For instance, in September 2005 price of natural gas went through a particular increase due to the Katrina hurricane, whereas high prices were observed during 2008 when the Brent oil exceeded $100 per barrel.

The coefficient of variation—which is a more appropriate measure when comparing data sets of different units, shows that the Henry Hub natural gas prices exhibit less variation relatively to the PJM and the Palo Verde electricity prices. This finding relates to the storable nature of natural gas, which implies that the availability of supplies can absorb part of the discrepancies between demand and supply.

The dataset for natural gas Henry hub spot-futures prices are available from 1990 and onwards. For the purpose of the study however, the statistical analysis is restricted for the time period available for electricity prices in order the estimation of the proposition to be feasible.
A comparison between the Henry hub spot and futures prices, indicate the presence of different patterns in the distribution for each holding period. For the near-by futures contracts, the statistical measures do not differentiate significantly from those of the spot price, since they exhibit similar positive skewness and approximately the same degree of kurtosis. The mean price for the monthly futures prices, according to the specific dataset, is at $7 per MBtus. However, the coefficient of variation in the case of the futures prices is lower than the spot prices. It is also evident that as the expiration date of the futures contract increases the statistical measures appear to be less intense.

### 4.7 Unit root tests in the prices of PJM, Palo Verde and Henry Hub markets

Econometric models used in commodity markets require that the data are stationary. A stochastic process, is said to be stationary if the mean and the variance remain constant over time, while the covariance between two time periods depends on the distance (or lag) of the time period rather than the actual time at which the covariance is computed.

According to the Augmented Dickey-Fuller (ADF) and the Phillips-Perron (PP) tests (table 4.5) the PJM and the Palo Verde spot prices are I(0) time series, since the probability values imply that the null hypothesis of a unit root is rejected. Stationarity in electricity spot prices is related to the mean reverting behavior they exhibit, which means that unexpected changes that gradually decline (temporal shocks) have a smaller effect in the subsequent prices. However, by applying the Kwiatkowski-Phillips-Schmidt-Shin (KPSS) test we arrive at the opposite conclusion since the null of stationarity is rejected. In the case of the Henry Hub natural gas spot prices, the null of a unit root for the series is rejected in some of the categories incorporated, whereas in other cases it is accepted. In the latter case, the order of integration has to be specified and for that purpose tests on the first differences are applied.

---

37 See the appendix of the specific chapter (tables 4.11 and 4.12) for the t-statistics, the critical values and a short description of each stationarity test employed in the specific analysis.
Chapter 4: Data description

Table 4.5: Unit root tests for the PJM, Palo Verde and Henry Hub spot prices

<table>
<thead>
<tr>
<th>Case</th>
<th>PJM</th>
<th>Palo Verde</th>
<th>Henry Hub</th>
</tr>
</thead>
<tbody>
<tr>
<td>ADF</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>1. No constant term and no linear trend</td>
<td>I(1)</td>
<td>I(1)</td>
<td>I(1)</td>
</tr>
<tr>
<td>2. Constant term but not a linear trend</td>
<td>I(0)</td>
<td>I(0)</td>
<td>I(0)</td>
</tr>
<tr>
<td>3. Constant term and a deterministic linear trend</td>
<td>I(0)</td>
<td>I(0)</td>
<td>I(1)</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Case</th>
<th>PJM</th>
<th>Palo Verde</th>
<th>Henry Hub</th>
</tr>
</thead>
<tbody>
<tr>
<td>Philips-Peron</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>1. No constant term and no linear trend</td>
<td>I(0)</td>
<td>I(0)</td>
<td>I(1)</td>
</tr>
<tr>
<td>2. Constant term but not a linear trend</td>
<td>I(0)</td>
<td>I(0)</td>
<td>I(0)</td>
</tr>
<tr>
<td>3. Constant term and a deterministic linear trend</td>
<td>I(0)</td>
<td>I(0)</td>
<td>I(0)</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Case</th>
<th>PJM</th>
<th>Palo Verde</th>
<th>Henry Hub</th>
</tr>
</thead>
<tbody>
<tr>
<td>KPSS</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>1. Intercept</td>
<td>I(1)</td>
<td>I(0)</td>
<td>I(0)</td>
</tr>
<tr>
<td>2. Trend and intercept</td>
<td>I(1)</td>
<td>I(1)</td>
<td>I(1)</td>
</tr>
</tbody>
</table>

Notes: For the ADF and the PP test: a: reject the null (unit root) at 1%, b: reject the null (unit root) at 5%, c: reject the null (unit root) at 10% level of significance
For the KPSS test: *: accept the null at 1%, **: accept the null at 5%, ***: accept the null at 10% level of significance.

The results indicate that the null hypothesis (i.e., a unit root in the first difference) is rejected; thus the Henry Hub natural gas spot price series are I(1) series. By applying the same rule on the futures prices we observe that the PJM series is I(0), whereas the Palo Verde price series is I(1) (Table 4.6). Thus, we should proceed the unit root test in order to specify the exact level of integration. As in the case of the spot price, the tests indicate that the series is integrated of order 1. Similarly to the Palo Verde monthly futures prices, the Henry hub futures prices for contracts maturing during the next month have a unit root.

Having examined the stationarity of the spot and futures electricity prices at the specific power markets, it stems that the existence of unit roots should be investigated on the basis or the difference between the futures and the contemporaneous spot electricity prices, which is the dependent variable in the empirical analysis of the theoretical proposition. All tests employed indicate that the basis estimated from PJM, Palo Verde and Mid-Columbia prices are I(0) (see appendix for the results). The stationarity of the parameter is by all means related to the fact that the basis is actually the difference between two time series, (the spot and the futures prices of a commodity) which is a typical example of a stationary variable, known also as difference-stationary variable.
Table 4.6: Unit root tests, PJM - Palo Verde - Henry Hub monthly futures prices

<table>
<thead>
<tr>
<th>Case</th>
<th>PJM</th>
<th>Palo Verde</th>
<th>Henry Hub</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>ADF</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>1. No constant term and no linear trend</td>
<td>I(1)</td>
<td>I(1)</td>
<td>I(1)</td>
</tr>
<tr>
<td>2. Constant term but not a linear trend</td>
<td>I(0)</td>
<td>I(1)</td>
<td>I(1)</td>
</tr>
<tr>
<td>3. Constant term and a deterministic linear trend</td>
<td>I(0)</td>
<td>I(1)</td>
<td>I(1)</td>
</tr>
<tr>
<td><strong>Philips-Peron</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>1. No constant term and no linear trend</td>
<td>I(1)</td>
<td>I(1)</td>
<td>I(1)</td>
</tr>
<tr>
<td>2. Constant term but not a linear trend</td>
<td>I(0)</td>
<td>I(1)</td>
<td>I(1)</td>
</tr>
<tr>
<td>3. Constant term and a deterministic linear trend</td>
<td>I(0)</td>
<td>I(1)</td>
<td>I(1)</td>
</tr>
<tr>
<td><strong>KPSS</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>1. Intercept</td>
<td>I(0)*</td>
<td>I(1)</td>
<td>I(0)*</td>
</tr>
<tr>
<td>2. Trend and intercept</td>
<td>I(1)</td>
<td>I(1)</td>
<td>I(1)</td>
</tr>
</tbody>
</table>

**Notes:** For the ADF and the PP test: a: reject the null (unit root) at 1%, b: reject the null (unit root) at 5%, c: reject the null (unit root) at 10% level of significance. For the KPSS test: *: accept the null at 1%, **: accept the null at 5%, ***: accept the null at 10% level of significance.

4.8 Electricity base load prices, the case of Mid-Columbia trading hub

Baseload generating units have higher capacity factor relatively to other facilities, i.e., they operate at a constant rate in order to supply the grid with electricity. Due to the use of less expensive fuels in their generation process, base load electricity rates are usually lower compared to the prices during the peak demand. Figure 4.9 shows average daily spot prices at the Mid-Columbia trading hub during the peak (from 7:00 am to 22:00 p.m.) and the off-peak hours (from 23:00 p.m. to 7:00 a.m).

**Figure 4.9:** Spot prices for electricity delivery during Peak and off-Peak hours in the Mid-Columbia Hub, January ‘03-June ‘09

**Source:** DataStream

Mid-Columbia is part of the Northwest power market in the US with the generation mix of electricity in the region consisting particularly of hydro, natural gas and coal. Given that hydro and natural gas are, according to FERC, used to fuel power units operating when demand for electricity is higher, it stems that coal represents the energy resource used in power production for base load needs.
Table 4.7: Summary statistics, Mid-Columbia hub (Jan. 2003-June 2009)

<table>
<thead>
<tr>
<th></th>
<th>Off-peak hours ($ per MWh)</th>
<th>Peak hours ($ per MWh)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Mean</td>
<td>42.1</td>
<td>52.3</td>
</tr>
<tr>
<td>Coef. of Var.</td>
<td>41.1%</td>
<td>35.6%</td>
</tr>
<tr>
<td>Min.</td>
<td>3.2</td>
<td>7.4</td>
</tr>
<tr>
<td>Max.</td>
<td>124.4</td>
<td>197.8</td>
</tr>
<tr>
<td>Median</td>
<td>41.4</td>
<td>49.8</td>
</tr>
<tr>
<td>St. Deviation</td>
<td>17.3</td>
<td>18.6</td>
</tr>
<tr>
<td>Skewness</td>
<td>0.4</td>
<td>1.3</td>
</tr>
<tr>
<td>Kurtosis</td>
<td>4.5</td>
<td>8.4</td>
</tr>
<tr>
<td>Ljung-Box (1)</td>
<td>1520.5</td>
<td>1396.1</td>
</tr>
<tr>
<td>Ljung-Box (2)</td>
<td>2934.3</td>
<td>2615.1</td>
</tr>
<tr>
<td>Ljung-Box (3)</td>
<td>4253.0</td>
<td>3703.2</td>
</tr>
<tr>
<td>Jarque-Bera</td>
<td>197.9</td>
<td>2520.1</td>
</tr>
<tr>
<td>Observations</td>
<td>1667</td>
<td>1667</td>
</tr>
</tbody>
</table>

Over the period considered the long-run equilibrium level during the off-peak hours is at $42 per MWh, whereas for the peak hours approximates $52 per MWh. In addition, electricity prices at the Mid-Columbia trading hub during the peak hours exhibit higher fluctuations. Even though, deviation from the average price occurs both for the peak and the off-peak hours, upward price movements are more pronounced in the former case. This situation can be observed by comparing the maximum values for each of the series (Table 4.7).

### 4.9 Central Appalachia coal prices

Coal prices are mainly influenced by the conditions prevailing in the market, mine operating - transportation costs and the quality of the commodity. Even though price differences are observed by region of production, the degree of variation is lower compared to other energy resources such as the natural gas.

**Figure 4.10: Coal Futures prices, NYMEX Central Appalachian**

The trend however reversed in 2008, when significant price movements were recorded, leading the average price at $90 per short ton and the deviation from the mean level at the
\$21 per short ton. Indicative of the price volatility during 2008 is the fact that the coefficient of variation ranged at a level twice as high than that of the previous years (Table 4.8).

**Table 4.8: Summary statistics of spot Central Appalachia coal prices, 2006-2008 (USD per ton)**

<table>
<thead>
<tr>
<th></th>
<th>2006</th>
<th>2007</th>
<th>2008</th>
<th>2009</th>
</tr>
</thead>
<tbody>
<tr>
<td>Mean</td>
<td>49.4</td>
<td>45.4</td>
<td>90.4</td>
<td>49.1</td>
</tr>
<tr>
<td>Coef. of Var.</td>
<td>9.3%</td>
<td>9.6%</td>
<td>22.8%</td>
<td>10.6%</td>
</tr>
<tr>
<td>Minimum</td>
<td>40.3</td>
<td>39.3</td>
<td>55.5</td>
<td>43.8</td>
</tr>
<tr>
<td>Maximum</td>
<td>58.0</td>
<td>56.9</td>
<td>143.5</td>
<td>64.3</td>
</tr>
<tr>
<td>Median</td>
<td>49.1</td>
<td>44.6</td>
<td>87.5</td>
<td>46.5</td>
</tr>
<tr>
<td>St. Deviation</td>
<td>4.6</td>
<td>4.4</td>
<td>20.6</td>
<td>5.2</td>
</tr>
<tr>
<td>Skew</td>
<td>0.0</td>
<td>0.6</td>
<td>0.2</td>
<td>1.4</td>
</tr>
<tr>
<td>Kurt.</td>
<td>-1.0</td>
<td>-0.4</td>
<td>-0.9</td>
<td>0.8</td>
</tr>
<tr>
<td>Observations</td>
<td>258</td>
<td>258</td>
<td>255</td>
<td>251</td>
</tr>
</tbody>
</table>

According to the EIA, the main factors that drove the increase in US coal prices were the increase in surcharges by the transportation sector in response to the rise of the oil prices and the increase in the demand for US coal internationally.

**4.10 Estimation of the Convenience Yield**

In the previous chapter, the implications on the relationship between electricity prices and the carrying costs of major fossil fuels in power generation have been demonstrated, according to which we have arrived at the relationship:

\[
\text{Basis}_{Elec}^{t,T} = C + b \times HR \times \left[ \frac{\text{Marginal Fuel}_{\text{Electricity}}}{\text{Marginal Fuel}_{\text{Electricity}}} + \frac{\text{SC}_{\text{t,T}}}{\text{Marginal Fuel}_{\text{Electricity}}} - Z_{\text{t,T}} \right] \tag{4.1}
\]

However, in the proposed relationship the fuel’s storage cost refers to an unknown parameter. The cost incorporates the sum of the expenses associated with storing a commodity, like inventory, warehouse, deterioration and insurance expenses. For instance, natural gas is stored mainly through injection in underground reservoirs, whereas the amount of storage is an indication of the balance between the commodity’s supply and demand. According to the EIA, the most common types of storing natural gas are depleted reservoirs, aquifers and storage in salt caverns.

Depleted storage can take place in shallow, high-deliverability depleted oil and gas reservoirs. The main advantage of this kind of storage is the existing pipeline infrastructure, combined with a number of useable wells and field gathering facilities. Aquifer storage refers to the injection of natural gas in underground facilities, which were initially filled with water (aquifers). These types of reservoirs, account for only 10\% to 15\% of total US storage deliverability and exist mainly in the Midwest, due to the lack of depleted oil and gas basins. Finally, salt cavern storage sites are solution-mined cavities in existing salt domes. These shallow cavities are filled with injected natural gas and act as high pressure storage vessels.
Storage costs vary by reservoir type. For instance, depleted reservoir costs are typically around $0.5 per MBtu/s, while salt dome storage costs are higher than $1.0 per MBtu/s. However, in our case we face the lack of information on both the type of storage facilities used in power plants and the precise cost of each type of storage.

Nevertheless, by rearranging the terms of the relationship it stems that the basis of electricity is linearly related to the net of storage convenience yield of the marginal fuel. Therefore, the relationship in (4.1) is re-written:

\[
\begin{align*}
\text{Basis}_t^{\text{Electricity}} &= c + b \times \text{HR} \times S_{t}^{\text{Marginal Fuel}} \times r_t + b \times \text{HR} \times S_{t}^{\text{Marginal Fuel}} - b \times \text{HR} \times Z_{t,T}^{\text{Marginal Fuel}} \\
&= c + b \times \text{HR} \times S_{t}^{\text{Marginal Fuel}} \times r_t - b \times \text{HR} \times \left[ Z_{t,T}^{\text{Marginal Fuel}} - S_{t}^{\text{Marginal Fuel}} \right] \\
&= c + b \times \text{HR} \times S_{t}^{\text{Marginal Fuel}} \times r_t - b \times \text{HR} \times \text{NZ}_{t,T}^{\text{Marginal Fuel}}
\end{align*}
\]

(4.2)

where \( \text{NZ}_{t,T}^{\text{Marginal Fuel}} \) expresses the net of storage convenience yield.

As it was mentioned in the previous chapter convenience yield represents the benefit of holding inventories of a commodity and has a critical position in the proposed inter-commodity relationship between electricity and the fuels used the generation process. The (net of storage) convenience yield is estimated as the difference between the spot and the discounted, by the risk free interest rate, futures price, i.e.,:

\[
\text{NZ}_{t,T} = S_t - F_{t,T} e^{TB(T-t)/365}
\]

(4.3)

where TB refers to the treasury bill yield and T-t to the time to maturity of the futures contract. At this section the convenience yield upon prices of natural gas and coal, which have been chosen as the marginal fuels in the merit order process are estimated.

<table>
<thead>
<tr>
<th>Holding Period</th>
<th>1-pos</th>
<th>3-pos</th>
<th>6-pos</th>
<th>12-pos*</th>
</tr>
</thead>
<tbody>
<tr>
<td>Observations</td>
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<td>1616</td>
<td>1616</td>
<td>1616</td>
</tr>
<tr>
<td>Negative</td>
<td>1018</td>
<td>1300</td>
<td>1330</td>
<td>1065</td>
</tr>
<tr>
<td>Positive</td>
<td>598</td>
<td>316</td>
<td>286</td>
<td>551</td>
</tr>
<tr>
<td>% negative</td>
<td>63%</td>
<td>80%</td>
<td>82%</td>
<td>66%</td>
</tr>
<tr>
<td>% positive</td>
<td>37%</td>
<td>20%</td>
<td>18%</td>
<td>34%</td>
</tr>
<tr>
<td>Mean</td>
<td>-0.11</td>
<td>-0.41</td>
<td>-0.59</td>
<td>-0.47</td>
</tr>
<tr>
<td>St. deviation</td>
<td>0.49</td>
<td>0.87</td>
<td>1.29</td>
<td>1.41</td>
</tr>
<tr>
<td>Maximum</td>
<td>8.91</td>
<td>12.64</td>
<td>13.05</td>
<td>12.81</td>
</tr>
<tr>
<td>Minimum</td>
<td>-3.06</td>
<td>-4.54</td>
<td>-4.94</td>
<td>-3.61</td>
</tr>
</tbody>
</table>

(*) 1, 3, 6 and 12 pos (-itions) denote 1, 3, 6 and 12 months to delivery of the futures contract

Table 4.9 and 4.10 respectively, show summary statistics of the convenience yield for the Henry Hub natural gas and Central Appalachia coal futures for different delivery periods (one month, three months, six months and twelve months to maturity). In the former case, the
average net convenience yield is negative implying that the spot natural gas prices tend to be lower than the futures prices. In contrast, the mean level of the convenience yield on Central Appalachia futures contracts is positive. With respect to the specific commodity, an inverted futures market is observed with spot prices being higher than futures prices.

Table 4.10: Summary statistics of convenience yields on Central Appalachia coal futures contracts (USD per ton)

<table>
<thead>
<tr>
<th>Holding Period</th>
<th>1-pos</th>
<th>3-pos</th>
<th>6-pos</th>
<th>12-pos</th>
</tr>
</thead>
<tbody>
<tr>
<td>Sample size</td>
<td>1471</td>
<td>1471</td>
<td>1471</td>
<td>1471</td>
</tr>
<tr>
<td>Negative</td>
<td>721</td>
<td>851</td>
<td>782</td>
<td>588</td>
</tr>
<tr>
<td>Positive</td>
<td>750</td>
<td>620</td>
<td>689</td>
<td>883</td>
</tr>
<tr>
<td>% negative</td>
<td>49%</td>
<td>58%</td>
<td>53%</td>
<td>40%</td>
</tr>
<tr>
<td>% positive</td>
<td>51%</td>
<td>42%</td>
<td>47%</td>
<td>60%</td>
</tr>
<tr>
<td>Mean</td>
<td>0.11</td>
<td>0.07</td>
<td>0.13</td>
<td>1.01</td>
</tr>
<tr>
<td>St. deviation</td>
<td>1.58</td>
<td>2.59</td>
<td>3.50</td>
<td>5.95</td>
</tr>
<tr>
<td>Maximum</td>
<td>11.19</td>
<td>17.51</td>
<td>21.81</td>
<td>25.30</td>
</tr>
<tr>
<td>Minimum</td>
<td>-3.95</td>
<td>-4.73</td>
<td>-5.53</td>
<td>-15.90</td>
</tr>
</tbody>
</table>

(*) 1, 3, 6 and 12 pos (itions) denote 1, 3, 6 and 12 months to delivery of the futures contract

Moreover, in both cases the average convenience yield increases as the holding period of the futures contract rises. Similar trend is recorded in the standard deviation, an indication which is also evident by the maximum and minimum estimates respectively.38

4.11 Heating and Cooling degrees days

As a final remark, in equation (4.2) we employ two additional variables, which are closely related to the demand for electricity and assumed to affect the pricing of power and the level of the fuel inventory (consequently the convenience yield) as well. This is the determinant of the temperature, expressed by the Heating Degree Days (HDD) and Cooling Degree Days (CDD) variables. Demand for power increases during the periods of high temperatures, since the need for air conditioning is almost entirely covered by electricity, whereas during periods of lower temperatures the heating needs increase, a fact that primarily affects the demand for natural gas and for power as well. The specific variables are measured as the average temperature departure from a specified level and can be considered as a more sophisticated approach relative to dummies employed to capture the seasonality in the demand for electricity. Therefore, expression (4.2) is written as:

\[
\text{Basis}_{t}^{\text{Electricity}} = c + b \times \text{HR} \times S_{\text{Marginal Fuel}}^{t} \times r_{t} - b \times \text{HR} \times \text{NZ}_{t}^{\text{Marginal Fuel}} + \text{HDD}_{t} + \text{CDD}_{t} \tag{4.4}
\]

with HDD and CDD parameters referring to estimates relative to reference level of temperature expected to prevail at the contract’s maturity.

According to the definition of the US Energy Information Administration a degree-day compares the outdoor temperature to a standard level of temperature. The more extreme the

---

38 The characteristics that the convenience yield on natural gas prices exhibit and its applications relative to the theory of storage are examined also in chapter five.
temperature, the higher the degree-day number will be; subsequently, the more energy will be required for space heating or cooling. Hot days, which require the use of energy for cooling needs are measured in cooling degree-days (CDD), whereas cold days are measured in heating degree-days (HDD). For instance, by assuming a reference level of temperature of 15°C\(^{39}\) – this is the reference price for the estimation of the variables in the study - and the mean temperature at a specific day at 25°C, then 10 CDD would be recorded. In contrast, if the mean daily temperature is at 3°C then 12 HDD (assuming the same reference level) would be recorded.

In order to empirically examine the proposed relationship, the estimation of HDD and CDD parameters is based on daily measurements of maximum and minimum air temperatures (\(T_{\text{max}}\) and \(T_{\text{min}}\)) and a reference temperature \(T_{\text{reference}}\), which corresponds to an estimate of the outside air temperature at which no artificial heating (or cooling) is required. Cooling degree days and Heating Degree Days are daily average estimates of weather stations located in each of the regions (energy markets) examined.

<table>
<thead>
<tr>
<th>Condition</th>
<th>Formula used</th>
</tr>
</thead>
<tbody>
<tr>
<td>(T_{\text{min}} &gt; T_{\text{reference}}) (\frac{T_{\text{max}} + T_{\text{min}}}{2} &gt; T_{\text{reference}})</td>
<td>(D_h = 0)</td>
</tr>
<tr>
<td>(T_{\text{max}} &gt; T_{\text{reference}})</td>
<td>(D_h = \frac{4}{3} (T_{\text{reference}} - T_{\text{min}} - (T_{\text{max}} - T_{\text{reference}}))/4)</td>
</tr>
<tr>
<td>(T_{\text{min}} &lt; T_{\text{reference}})</td>
<td>(D_h = T_{\text{reference}} - \frac{T_{\text{max}} + T_{\text{min}}}{2})</td>
</tr>
</tbody>
</table>

Raw data are obtained from the website wunderground.com. For instance, in the case of the PJM Interconnection, data are collected for each of the states that the specific market covers and specifically from major airports such as the JFK International airport in the New York, the Northeast Philadelphia Airport in Pennsylvania, the Arlington Municipal Airport in Washington and others. The final series represents the average value of each location’s estimate. The daily result for HDD (\(D_h\)) stems from the formulae appearing on table 4.11, according to the criterion that fits the data. Respectively, CDD (\(D_c\)) is selected from the standards on table 4.12.

It should be mentioned that the HDD and CDD parameters refer to the temperature conditions at the date that the delivery of the commodity has to take place. For that purpose, as a proxy for the specific estimation we use the average price for the delivery period of the previous four years.

\(^{39}\) Similarly to Celsius as a scale and unit of temperature, the Fahrenheit scale can be also applied. In our case data with respect to daily temperatures at the regions examined are given in Celsius degrees (www.wunderground.com/history)
### Table 4.12: Conditions for the estimation of the heating degree days

<table>
<thead>
<tr>
<th>Condition</th>
<th>Formula used</th>
</tr>
</thead>
<tbody>
<tr>
<td>$T_{\text{max}} &lt; T_{\text{ref}}$</td>
<td>$D_c = 0$</td>
</tr>
<tr>
<td>$(T_{\text{max}} + T_{\text{min}})/2 &lt; T_{\text{ref}}$</td>
<td>$D_c = (T_{\text{max}} - T_{\text{ref}})/4$</td>
</tr>
<tr>
<td>$T_{\text{min}} \leq T_{\text{ref}}$</td>
<td>$D_c = (T_{\text{max}} - T_{\text{ref}})/2 - (T_{\text{ref}} - T_{\text{min}})/4$</td>
</tr>
<tr>
<td>$T_{\text{min}} &gt; T_{\text{ref}}$</td>
<td>$D_c = (T_{\text{max}} + T_{\text{min}})/2 - T_{\text{ref}}$</td>
</tr>
</tbody>
</table>
## Appendix

### Table 4.13: Data Description

<table>
<thead>
<tr>
<th>Commodity</th>
<th>Source</th>
<th>Construction</th>
<th>Data period</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Electricity</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>PJM Spot prices</td>
<td>Dow Jones Electricity Prices Indices, obtained from Datasream.</td>
<td>Volume-weighted price indexes are based on Dow Jones Firm, on-peak daily day ahead electricity prices. Off-peak prices are estimated from data obtained from the PJM website during the specific hours of the day. Quotation: USD per MWh.</td>
<td>1/1/2003 until 30/6/2009</td>
</tr>
<tr>
<td>PJM Futures Prices</td>
<td>NYMEX daily settlement prices obtained from Reuters-Ecowin database.</td>
<td>40 MWh per peak day (between 10 and 23 days) depending on the month. Depending on the number of peak days in the month, the number of MWh will vary (between 700 MWh and 922 MWh). Quotation: USD per MWh.</td>
<td>1/1/2003 until 30/6/2009</td>
</tr>
<tr>
<td>Palo Verde Spot prices</td>
<td>Dow Jones Electricity Prices Indices, obtained from Datasream.</td>
<td>Volume-weighted price indexes are based on Dow Jones Firm, on-peak daily day ahead electricity prices. Quotation: USD per MWh.</td>
<td>1/1/2003 until 30/6/2009</td>
</tr>
<tr>
<td>Palo Verde Futures prices</td>
<td>NYMEX daily settlement prices obtained from Reuters-Ecowin database.</td>
<td>Palo Verde Electricity Price Index Futures traded at NYMEX. Quotation: USD per MWh.</td>
<td>1/1/2004 until 30-6/2009</td>
</tr>
<tr>
<td>Mid-Columbia Spot prices</td>
<td>Dow Jones Off-Peak Electricity Prices Indices from Datasream.</td>
<td>Volume-weighted price indexes are based on Dow Jones Firm, off-peak daily day ahead electricity prices. Quotation: USD per MWh.</td>
<td>3/1/2000 until 30/6/2009</td>
</tr>
<tr>
<td>Mid-Columbia Futures prices</td>
<td>NYMEX daily settlement prices obtained from Reuters-Ecowin database.</td>
<td>Delivery during the off-peak hours of the day. Depending on the number of days in the month, the number of MWh will vary. Quotation: USD per MWh.</td>
<td>3/8/2004 until 30/6/2009</td>
</tr>
<tr>
<td><strong>Natural Gas</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Henry Hub Futures prices</td>
<td>Price data are based on NYMEX daily settlement prices obtained from Reuters-Ecowin database. Seventy-two consecutive trading months commencing with the next calendar month.</td>
<td>Trading Unit: 10,000 million British thermal units (mmbtu). Price Quotations: USD per MMBtu.</td>
<td>25/3/1993 until 30/6/2009</td>
</tr>
<tr>
<td><strong>Coal</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Central Appalachian Coal Futures prices</td>
<td>Price data are based on NYMEX daily settlement prices obtained from Reuters-Ecowin database.</td>
<td>Trading Unit: 1,550 tons of coal. Price Quotation: USD per ton.</td>
<td>1/1/2004 until 30/6/2009</td>
</tr>
</tbody>
</table>
### Table 4.1: Unit root tests for the PJM, Palo Verde and Henry Hub spot prices

<table>
<thead>
<tr>
<th>Case</th>
<th>PJM</th>
<th>Palo Verde</th>
<th>Henry Hub</th>
</tr>
</thead>
<tbody>
<tr>
<td>1. No constant term and no linear trend</td>
<td>-1,575 (0.109)*</td>
<td>-1,588 (0.107)</td>
<td>-1,075 (0.256)</td>
</tr>
<tr>
<td>2. Constant term but not a linear trend</td>
<td>-5,858 (0.000)</td>
<td>-6,159 (0.000)</td>
<td>-2,981 (0.037)</td>
</tr>
<tr>
<td>3. Constant term and a deterministic linear trend</td>
<td>-6,142 (0.000)</td>
<td>-6,175 (0.000)</td>
<td>-2,932 (0.153)</td>
</tr>
</tbody>
</table>

### Table 4.15: Unit root tests for the PJM, Palo Verde and Henry Hub monthly futures prices

<table>
<thead>
<tr>
<th>Case</th>
<th>PJM</th>
<th>Palo Verde</th>
<th>Henry Hub</th>
</tr>
</thead>
<tbody>
<tr>
<td>1. No constant term and no linear trend</td>
<td>-1,411 (0.148)*</td>
<td>-0,558 (0.476)</td>
<td>-0,801 (0.369)</td>
</tr>
<tr>
<td>2. Constant term but not a linear trend</td>
<td>-4,370 (0.000)</td>
<td>-1,584 (0.490)</td>
<td>-2,341 (0.159)</td>
</tr>
<tr>
<td>3. Constant term and a deterministic linear trend</td>
<td>-4,499 (0.002)</td>
<td>-1,6973 (0.752)</td>
<td>-2,232 (0.471)</td>
</tr>
</tbody>
</table>

### Notes:
- The reported values in the table are the estimated t-statistics and the p-values in the parentheses for the unit root test, according to the three specific situations. The calculated statistics are those reported for the Dickey-Fuller and the Philips-Perron tests. The critical values (for both tests) at 1%, 5% and 10% levels of significance are: for Case 1: -2.57, -1.94 and -1.62; for Case 2: -3.43, -2.86 and -2.57; and for Case 3: -3.96, -3.41 and -3.13 respectively.
- The KPSS test is based on a Lagrange Multiplier autocorrelation procedure and tests the null hypothesis that the series is stationary against the alternative hypothesis of non-stationarity. The null hypothesis is accepted if the test statistic is lower than the critical value. In the parentheses appear the asymptotic critical values for 1%, 5% and 10% level of significance.
Table 4.16: Unit root tests for the Mid-Columbia spot electricity prices during the off-peak and the peak hours

<table>
<thead>
<tr>
<th>Case</th>
<th>Off-peak Prices</th>
<th>Peak Prices</th>
<th>Off-peak Prices</th>
<th>Peak Prices</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>ADF</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>1. No constant term and no linear trend</td>
<td>-1.893 (0.056)</td>
<td>-1.751 (0.000)</td>
<td>I(1)</td>
<td>I(0)</td>
</tr>
<tr>
<td>2. Constant term but not a linear trend</td>
<td>-4.974 (0.000)</td>
<td>-5.378 (0.000)</td>
<td>I(0)</td>
<td>I(0)</td>
</tr>
<tr>
<td>3. Constant term and a deterministic linear trend</td>
<td>-4.976 (0.000)</td>
<td>-5.447 (0.000)</td>
<td>I(0)</td>
<td>I(0)</td>
</tr>
<tr>
<td>Philips-Peron</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>1. No constant term and no linear trend</td>
<td>-2.008 (0.043)</td>
<td>-1.749 (0.076)</td>
<td>I(1)</td>
<td>I(1)</td>
</tr>
<tr>
<td>2. Constant term but not a linear trend</td>
<td>-5.717 (0.000)</td>
<td>-7.690 (0.000)</td>
<td>I(0)</td>
<td>I(0)</td>
</tr>
<tr>
<td>3. Constant term and a deterministic linear trend</td>
<td>-5.729 (0.000)</td>
<td>-8.004 (0.000)</td>
<td>I(0)</td>
<td>I(0)</td>
</tr>
<tr>
<td>KPSS</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>1. Intercept</td>
<td>0.353 (0.74-0.46-0.38)</td>
<td>0.781 (0.74-0.46-0.38)</td>
<td>I(0)</td>
<td>I(1)</td>
</tr>
<tr>
<td>2. Trend and intercept</td>
<td>0.156 (0.22; 0.15; 0.12)</td>
<td>0.263 (0.22; 0.15; 0.12)</td>
<td>I(0)</td>
<td>I(0)</td>
</tr>
</tbody>
</table>

Notes: Similar as in table 4.14

Table 4.17: Unit root tests for the PJM, Palo Verde and Mid-C basis (the case of one month to maturity)

<table>
<thead>
<tr>
<th>Case</th>
<th>PJM</th>
<th>Palo Verde</th>
<th>Mid-C</th>
<th>PJM</th>
<th>Palo Verde</th>
<th>Mid-C</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>ADF</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>1. No constant term and no linear trend</td>
<td>-16.510 (0.000)</td>
<td>-4.210 (0.000)</td>
<td>-5.303 (0.000)</td>
<td>I(0)</td>
<td>I(0)</td>
<td>I(0)</td>
</tr>
<tr>
<td>2. Constant term but not a linear trend</td>
<td>-16.613 (0.000)</td>
<td>-4.974 (0.000)</td>
<td>-7.370 (0.000)</td>
<td>I(0)</td>
<td>I(0)</td>
<td>I(0)</td>
</tr>
<tr>
<td>3. Constant term and a deterministic linear trend</td>
<td>-16.854 (0.000)</td>
<td>-9.153 (0.000)</td>
<td>-7.431 (0.000)</td>
<td>I(0)</td>
<td>I(0)</td>
<td>I(0)</td>
</tr>
<tr>
<td>Philips-Peron</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>1. No constant term and no linear trend</td>
<td>-16.401 (0.000)</td>
<td>-6.187 (0.000)</td>
<td>-7.016 (0.000)</td>
<td>I(0)</td>
<td>I(0)</td>
<td>I(0)</td>
</tr>
<tr>
<td>2. Constant term but not a linear trend</td>
<td>-16.480 (0.000)</td>
<td>-7.227 (0.000)</td>
<td>-9.340 (0.000)</td>
<td>I(0)</td>
<td>I(0)</td>
<td>I(0)</td>
</tr>
<tr>
<td>3. Constant term and a deterministic linear trend</td>
<td>-16.665 (0.000)</td>
<td>-8.901 (0.000)</td>
<td>-9.496 (0.000)</td>
<td>I(0)</td>
<td>I(0)</td>
<td>I(0)</td>
</tr>
<tr>
<td>KPSS</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>1. Intercept</td>
<td>0.478 (0.74-0.46-0.38)</td>
<td>2.228 (0.74-0.46-0.38)</td>
<td>0.237 (0.74-0.46-0.38)</td>
<td>I(0)</td>
<td>I(1)</td>
<td>I(0)</td>
</tr>
<tr>
<td>2. Trend and intercept</td>
<td>0.096 (0.22; 0.15; 0.12)</td>
<td>0.277 (0.22; 0.15; 0.12)</td>
<td>0.165 (0.22; 0.15; 0.12)</td>
<td>I(0)</td>
<td>I(0)</td>
<td>I(0)</td>
</tr>
</tbody>
</table>

Notes: Similar as in table 4.14
### Table 4.18: Unit root tests for the Central Appalachia coal prices

<table>
<thead>
<tr>
<th>Case</th>
<th>Spot</th>
<th>1-pos</th>
<th>3-pos</th>
<th>6-pos</th>
<th>12-pos</th>
</tr>
</thead>
<tbody>
<tr>
<td>1. No constant term and no linear trend</td>
<td>-0.3553 (0.5570)</td>
<td>-0.3587 (0.5557)</td>
<td>-0.4659 (0.5137)</td>
<td>-0.4231 (0.5308)</td>
<td>-0.2264 (0.6048)</td>
</tr>
<tr>
<td>ADF 2. Constant term but not a linear trend</td>
<td>-1.8846 (0.3389)</td>
<td>-1.3449 (0.6104)</td>
<td>-1.9341 (0.3167)</td>
<td>-1.9937 (0.2898)</td>
<td>-2.0695 (0.2573)</td>
</tr>
<tr>
<td>3. Constant term and a deterministic linear trend</td>
<td>-0.3559 (0.4786)</td>
<td>-0.5104 (0.4955)</td>
<td>-0.4587 (0.5166)</td>
<td>-0.4015 (0.5392)</td>
<td>-0.2149 (0.6089)</td>
</tr>
<tr>
<td>Philips- Peron 1. No constant term and no linear trend</td>
<td>-1.9752 (0.2980)</td>
<td>-1.9245 (0.3211)</td>
<td>-1.9256 (0.3206)</td>
<td>-1.9526 (0.3082)</td>
<td>-2.0609 (0.2609)</td>
</tr>
<tr>
<td>2. Constant term but not a linear trend</td>
<td>-0.3509 (0.4786)</td>
<td>-0.5104 (0.4955)</td>
<td>-0.4587 (0.5166)</td>
<td>-0.4015 (0.5392)</td>
<td>-0.2149 (0.6089)</td>
</tr>
<tr>
<td>3. Constant term and a deterministic linear trend</td>
<td>-1.8362 (0.6867)</td>
<td>-1.7769 (0.7157)</td>
<td>-1.7685 (0.7197)</td>
<td>-1.8076 (0.7008)</td>
<td>-1.9174 (0.6448)</td>
</tr>
<tr>
<td>KPSS 1. Intercept</td>
<td>0.6301 (0.74; 0.46; 0.38)</td>
<td>13.86732 (0.74; 0.46; 0.38)</td>
<td>0.5636 (0.74; 0.46; 0.38)</td>
<td>0.6631 (0.74; 0.46; 0.38)</td>
<td>1.2315 (0.74; 0.46; 0.38)</td>
</tr>
<tr>
<td>2. Trend and intercept</td>
<td>0.2809 (0.22; 0.15; 0.12)</td>
<td>30.5820 (0.22; 0.15; 0.12)</td>
<td>0.2800 (0.22; 0.15; 0.12)</td>
<td>0.2761 (0.22; 0.15; 0.12)</td>
<td>0.2538 (0.22; 0.15; 0.12)</td>
</tr>
</tbody>
</table>

**Notes:** Similar as in table 4.14

### Table 4.19: Unit root tests for the PJM basis

<table>
<thead>
<tr>
<th>Case</th>
<th>1-pos</th>
<th>3-pos</th>
<th>6-pos</th>
<th>12-pos</th>
</tr>
</thead>
<tbody>
<tr>
<td>1. No constant term and no linear trend</td>
<td>-16.510 (0.000)</td>
<td>-8.298 (0.000)</td>
<td>-19.158 (0.000)</td>
<td>-8.406 (0.000)</td>
</tr>
<tr>
<td>ADF 2. Constant term but not a linear trend</td>
<td>-16.613 (0.000)</td>
<td>-8.391 (0.000)</td>
<td>-19.158 (0.000)</td>
<td>-8.869 (0.000)</td>
</tr>
<tr>
<td>3. Constant term and a deterministic linear trend</td>
<td>-16.859 (0.000)</td>
<td>-8.390 (0.000)</td>
<td>-19.350 (0.000)</td>
<td>-8.953 (0.000)</td>
</tr>
<tr>
<td>Philips- Peron 1. No constant term and no linear trend</td>
<td>-16.401 (0.000)</td>
<td>-11.391 (0.000)</td>
<td>-17.154 (0.000)</td>
<td>-12.041 (0.000)</td>
</tr>
<tr>
<td>2. Constant term but not a linear trend</td>
<td>-16.479 (0.000)</td>
<td>-11.500 (0.000)</td>
<td>-17.152 (0.000)</td>
<td>-11.935 (0.000)</td>
</tr>
<tr>
<td>3. Constant term and a deterministic linear trend</td>
<td>-16.666 (0.000)</td>
<td>-11.499 (0.000)</td>
<td>-17.271 (0.000)</td>
<td>-11.389 (0.000)</td>
</tr>
<tr>
<td>KPSS 1. Intercept</td>
<td>0.478 (0.74; 0.46; 0.38)</td>
<td>0.039 (0.74; 0.46; 0.38)</td>
<td>0.510 (0.74; 0.46; 0.38)</td>
<td>0.352 (0.74; 0.46; 0.38)</td>
</tr>
<tr>
<td>2. Trend and intercept</td>
<td>0.096 (0.22; 0.15; 0.12)</td>
<td>0.036 (0.22; 0.15; 0.12)</td>
<td>0.108 (0.22; 0.15; 0.12)</td>
<td>0.146 (0.22; 0.15; 0.12)</td>
</tr>
</tbody>
</table>

**Notes:** Similar as in table 4.14
### Table 4.20: Unit root tests for the Palo Verde basis

<table>
<thead>
<tr>
<th>Case</th>
<th>1-pos</th>
<th>3-pos</th>
<th>6-pos</th>
<th>12-pos</th>
</tr>
</thead>
<tbody>
<tr>
<td>1. No constant term and no linear trend</td>
<td>-5.983 (0.000)</td>
<td>-5.189 (0.000)</td>
<td>-4.665 (0.000)</td>
<td>-4.419 (0.000)</td>
</tr>
<tr>
<td>2. Constant term but not a linear trend</td>
<td>-5.227 (0.000)</td>
<td>-6.387 (0.000)</td>
<td>-7.449 (0.000)</td>
<td>-4.589 (0.001)</td>
</tr>
<tr>
<td>3. Constant term and a deterministic linear trend</td>
<td>-7.368 (0.000)</td>
<td>-6.654 (0.000)</td>
<td>-7.444 (0.000)</td>
<td>-2.307 (0.020)</td>
</tr>
<tr>
<td>1. No constant term and no linear trend</td>
<td>-10.081 (0.000)</td>
<td>-10.792 (0.000)</td>
<td>-7.249 (0.000)</td>
<td>-4.370 (0.000)</td>
</tr>
<tr>
<td>2. Constant term but not a linear trend</td>
<td>-11.761 (0.000)</td>
<td>-13.521 (0.000)</td>
<td>-7.254 (0.000)</td>
<td>-4.122 (0.000)</td>
</tr>
<tr>
<td>3. Constant term and a deterministic linear trend</td>
<td>-14.056 (0.000)</td>
<td>-14.145 (0.000)</td>
<td>-5.781 (0.000)</td>
<td>-2.631 (0.000)</td>
</tr>
</tbody>
</table>

#### ADF

**Notes:** Similar as in table 4.14

### Table 4.21: Unit root tests for the Mid-Columbia basis

<table>
<thead>
<tr>
<th>Case</th>
<th>1-pos</th>
<th>3-pos</th>
<th>6-pos</th>
<th>12-pos</th>
</tr>
</thead>
<tbody>
<tr>
<td>1. No constant term and no linear trend</td>
<td>-4.450 (0.000)</td>
<td>-3.325 (0.000)</td>
<td>-3.437 (0.000)</td>
<td>-2.771 (0.006)</td>
</tr>
<tr>
<td>2. Constant term but not a linear trend</td>
<td>-6.644 (0.000)</td>
<td>-5.606 (0.000)</td>
<td>-4.990 (0.000)</td>
<td>-5.536 (0.000)</td>
</tr>
<tr>
<td>3. Constant term and a deterministic linear trend</td>
<td>-7.063 (0.000)</td>
<td>-5.669 (0.000)</td>
<td>-4.996 (0.000)</td>
<td>-5.607 (0.000)</td>
</tr>
<tr>
<td>1. No constant term and no linear trend</td>
<td>-4.385 (0.000)</td>
<td>-3.953 (0.000)</td>
<td>-5.100 (0.000)</td>
<td>-3.170 (0.000)</td>
</tr>
<tr>
<td>2. Constant term but not a linear trend</td>
<td>-7.365 (0.000)</td>
<td>-5.898 (0.000)</td>
<td>-5.088 (0.000)</td>
<td>-5.716 (0.000)</td>
</tr>
<tr>
<td>3. Constant term and a deterministic linear trend</td>
<td>-7.858 (0.000)</td>
<td>-5.967 (0.000)</td>
<td>-3.354 (0.001)</td>
<td>-5.797 (0.000)</td>
</tr>
</tbody>
</table>

#### KPSS

**Notes:** Similar as in table 4.14
Table 4.22: Unit root tests for the compounded spot Henry hub gas price by the interest rate (monthly, three-months, six-months and twelve-months interest rate)

<table>
<thead>
<tr>
<th>Case</th>
<th>1m</th>
<th>3m</th>
<th>6m</th>
<th>12m</th>
<th>1m</th>
<th>3m</th>
<th>6m</th>
<th>12m*</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>ADF</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>1. No constant term and no linear trend</td>
<td>-1.003 (0.284)</td>
<td>-0.979 (0.293)</td>
<td>-0.924 (0.316)</td>
<td>0.928 (0.314)</td>
<td>I(1)</td>
<td>I(1)</td>
<td>I(1)</td>
<td>I(1)</td>
</tr>
<tr>
<td>2. Constant term but not a linear trend</td>
<td>-1.514 (0.526)</td>
<td>-1.508 (0.529)</td>
<td>-1.466 (0.551)</td>
<td>-1.547 (0.510)</td>
<td>I(1)</td>
<td>I(1)</td>
<td>I(1)</td>
<td>I(1)</td>
</tr>
<tr>
<td>3. Constant term and a deterministic linear trend</td>
<td>-1.405 (0.859)</td>
<td>-1.402 (0.861)</td>
<td>-1.338 (0.878)</td>
<td>-1.431 (0.851)</td>
<td>I(1)</td>
<td>I(1)</td>
<td>I(1)</td>
<td>I(1)</td>
</tr>
<tr>
<td>Philips-Peron</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>1. No constant term and no linear trend</td>
<td>-1.113 (0.241)</td>
<td>-1.005 (0.283)</td>
<td>-1.066 (0.282)</td>
<td>1.013 (0.279)</td>
<td>I(1)</td>
<td>I(1)</td>
<td>I(1)</td>
<td>I(1)</td>
</tr>
<tr>
<td>2. Constant term but not a linear trend</td>
<td>-1.833 (0.360)</td>
<td>-1.567 (0.499)</td>
<td>-1.648 (0.457)</td>
<td>-1.734 (0.412)</td>
<td>I(1)</td>
<td>I(1)</td>
<td>I(1)</td>
<td>I(1)</td>
</tr>
<tr>
<td>3. Constant term and a deterministic linear trend</td>
<td>-1.656 (0.770)</td>
<td>-1.459 (0.843)</td>
<td>-1.523 (0.821)</td>
<td>-1.625 (0.783)</td>
<td>I(1)</td>
<td>I(1)</td>
<td>I(1)</td>
<td>I(1)</td>
</tr>
<tr>
<td>KPSS</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>1. Intercept</td>
<td>1.107 (0.24; 0.15; 0.12)</td>
<td>1.098 (0.74-0.46-0.38)</td>
<td>1.086 (0.74-0.46-0.38)</td>
<td>1.048 (0.74-0.46-0.38)</td>
<td>I(1)</td>
<td>I(1)</td>
<td>I(1)</td>
<td>I(1)</td>
</tr>
<tr>
<td>2. Trend and intercept</td>
<td>1.051 (0.22; 0.15; 0.12)</td>
<td>1.048 (0.22; 0.15; 0.12)</td>
<td>1.027 (0.22; 0.15; 0.12)</td>
<td>1.001 (0.22; 0.15; 0.12)</td>
<td>I(1)</td>
<td>I(1)</td>
<td>I(1)</td>
<td>I(1)</td>
</tr>
</tbody>
</table>

Notes: Similar as in table 4.14
* 1m up to 12m denotes the unit root tests for the spot natural gas price multiplied by one, three, six and twelve month interest rates respectively
Table 4.23: Unit root tests for the compounded spot Appalachia coal price by the interest rate (monthly, three-months, six-months and twelve-months interest rate)

<table>
<thead>
<tr>
<th>Case</th>
<th>1m</th>
<th>3m</th>
<th>6m</th>
<th>12m</th>
<th>1m</th>
<th>3m</th>
<th>6m</th>
<th>12m*</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>ADF</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>1. No constant term and no linear trend</td>
<td>-0.892</td>
<td>-0.714</td>
<td>-0.785</td>
<td>-0.779</td>
<td>I(1)</td>
<td>I(1)</td>
<td>I(1)</td>
<td>I(1)</td>
</tr>
<tr>
<td></td>
<td>(0.329)</td>
<td>(0.407)</td>
<td>(0.376)</td>
<td>(0.376)</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>2. Constant term but not a linear trend</td>
<td>-1.394</td>
<td>-0.930</td>
<td>-1.099</td>
<td>-1.100</td>
<td>I(1)</td>
<td>I(1)</td>
<td>I(1)</td>
<td>I(1)</td>
</tr>
<tr>
<td></td>
<td>(0.587)</td>
<td>(0.778)</td>
<td>(0.718)</td>
<td>(0.720)</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>3. Constant term and a deterministic linear trend</td>
<td>-2.175</td>
<td>-1.973</td>
<td>-2.014</td>
<td>-2.182</td>
<td>I(1)</td>
<td>I(1)</td>
<td>I(1)</td>
<td>I(1)</td>
</tr>
<tr>
<td></td>
<td>(0.501)</td>
<td>(0.639)</td>
<td>(0.590)</td>
<td>(0.604)</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Philips-Peron</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>1. No constant term and no linear trend</td>
<td>-0.925</td>
<td>-0.782</td>
<td>-0.728</td>
<td>-0.729</td>
<td>I(1)</td>
<td>I(1)</td>
<td>I(1)</td>
<td>I(1)</td>
</tr>
<tr>
<td></td>
<td>(0.316)</td>
<td>(0.378)</td>
<td>(0.405)</td>
<td>(0.450)</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>2. Constant term but not a linear trend</td>
<td>-1.574</td>
<td>-1.194</td>
<td>-0.863</td>
<td>-0.854</td>
<td>I(1)</td>
<td>I(1)</td>
<td>I(1)</td>
<td>I(1)</td>
</tr>
<tr>
<td></td>
<td>(0.496)</td>
<td>(0.679)</td>
<td>(0.799)</td>
<td>(0.710)</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>3. Constant term and a deterministic linear trend</td>
<td>-2.316</td>
<td>-2.104</td>
<td>-1.827</td>
<td>1.825</td>
<td>I(1)</td>
<td>I(1)</td>
<td>I(1)</td>
<td>I(1)</td>
</tr>
<tr>
<td></td>
<td>(0.425)</td>
<td>(0.542)</td>
<td>(0.691)</td>
<td>(0.609)</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>KPSS</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>1. Intercept</td>
<td>1.616</td>
<td>1.665</td>
<td>1.582</td>
<td>1.589</td>
<td>I(1)</td>
<td>I(1)</td>
<td>I(1)</td>
<td>I(1)</td>
</tr>
<tr>
<td></td>
<td>(0.24; 0.46; 0.38)</td>
<td>(0.74; 0.46; 0.38)</td>
<td>(0.74; 0.46; 0.38)</td>
<td>(0.74; 0.46; 0.38)</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>2. Trend and intercept</td>
<td>0.931</td>
<td>0.905</td>
<td>0.813</td>
<td>0.841</td>
<td>I(1)</td>
<td>I(1)</td>
<td>I(1)</td>
<td>I(1)</td>
</tr>
<tr>
<td></td>
<td>(0.22; 0.15; 0.12)</td>
<td>(0.22; 0.15; 0.12)</td>
<td>(0.22; 0.15; 0.12)</td>
<td>(0.22; 0.15; 0.12)</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Notes: Similar as in table 4.14
* 1m up to 12m denotes the unit root tests for the spot coal price multiplied by one, three, six and twelve month interest rates respectively
Chapter 5: Empirical analysis-The case of natural gas in power generation

5.1 Introduction

In this section the proposition conveying the basis of electricity prices with the (marginal) fuel’s carrying costs and demand related variables (cooling and heating degree-days) is empirically examined. According to the merit order dispatch, natural gas power plants provide power to the grid when demand for electricity is higher (peak hours). Natural gas therefore, is combusted to generate electricity enabling in this way stored energy to be transformed into usable power.

The introduction of convenience yield as a proxy of the level of inventory in the proposition indicates that the inverse relationship proposed at a theoretical level (cost of carry theory) should be validated with historical data as well. In any other case, the results from the regression analysis may be inconclusive. For that purpose, the interest adjusted basis, proposed by Fama and French, is incorporated as it is considered a standard test on the implications of the storage theory. Even though the interest adjusted basis aims, by inception, to deal with the lack of storage data, in our case the negative relationship between inventory and convenience yield can be tested, given that data of US gas in storage (and for coal as well in the following chapter) are regularly reported by the EIA. This direct test is obtained by regressing estimated convenience yield of Henry hub futures contracts on the logarithm of stock level (see Appendix C).

5.2 Natural gas, inventory and convenience yield

Storage is an important component of natural gas supply because while production tends to be relatively constant over the year, consumption increases during the winter season as demand for heating rises. The need for natural gas storage capacity implies the presence of a yearly pattern as gas is withdrawn from reserve wells during the winter and replenished with injections during the spring and summer. In addition, the increase in the demand for natural gas is usually followed by higher prices in the spot market mainly due to the limited short-term alternatives for heating purposes.

Figure 5.1 depicts spot natural gas prices and working gas in storage (monthly average values on both cases) measured in metric cubic feet (Mcf). The figure shows that the Henry Hub spot price exhibits a negative relationship with the level of inventory. The only exception in this pattern is the unusual high price in September 2005, despite the adequate inventory supplies. This is due to the hurricanes along the US Golf coast that caused an equivalent of 4% of gas production in the US to be shut for a year.

40 http://www.eia.gov/dnav/ng/ng_stor_wkly_s1_w.htm
41 A million of Btus is roughly equivalent to a thousand cubic feet of natural gas
On the other hand, Figure 5.2 illustrates the relationship between convenience yield and working gas in storage. The plot indicates that the inverse relationship, proposed by the storage theory, is considerably accepted since the convenience yield is lower when the level of natural gas’ reserves increases and vice versa.

However, diagrams cannot be considered as rigid tests for confirming theoretical relationships. Due to the difficulty in measuring appropriately the inventory of metals, Fama and French (1988) proposed an indirect test based on the variation of spot and futures
prices. Instead of directly examining the inventory-convenience yield relationship, the implications of the theory of storage were tested through the variation of spot and futures prices. That view relies on the fact that supply or demand shocks, cause approximately equal changes in spot and futures prices when inventory levels are high, whereas spot prices tend to be more volatile than futures prices, in cases of lower inventory levels. Fama and French evaluated their proposition by considering the interest-adjusted basis, which is given by the relationship:

$$\frac{F_{t,T} - S_t}{S_t} - r_{t,T} = \frac{W_{t,T} - Z_{t,T}}{S_t}$$

(5.1)

where $r_{t,T}$ is the interest rate at which an investor can borrow or lend money and $W_{t,T}$ denotes the warehouse costs. According to (5.1), the interest-adjusted basis (left-hand side) is the difference between the relative warehousing costs ($W_{t,T}/S_t$) and the relative convenience yield ($Z_{t,T}/S_t$).

Following certain assumptions (i.e., constant marginal warehousing costs, decreasing convenience yield with increase in inventory and higher variation in the marginal convenience yield than in the warehousing costs) the interest-adjusted basis has been applied in the literature for commodities, such as metals and copper in order to test certain assumptions with respect to the convenience yield. The sign of the interest-adjusted basis is a proxy for higher (positive interest-adjusted basis) or lower (negative interest-adjusted basis) inventory levels. Specifically, the proposition predicts that shocks produce more variation in spot and futures prices when inventory is lower (i.e., the case of a negative interest-adjusted basis) rather when abundant supplies exist in a commodity’s market.

Table 5.1 shows estimations of the interest adjusted basis for the Henry Hub natural gas prices, that incorporates a more extensive (relative to the observations used in Figures 5.1 and 5.2) data set covering the period from November 1993 until June 2009 for different holding periods. In particular, Table 5.1 shows the number of total observations, the sum of positive and negative interest-adjusted bases and finally the mean and the standard deviation estimations.

Based on the presumptions of the indirect test, shocks produce more variation in the spot and futures prices at lower inventory levels (or negative signs of the interest adjusted basis respectively). In order to test the implications of the Fama and French approach a hypothesis test is conducted, according to which the null ($H_0$) asserts that the standard deviation of the negative interest adjusted basis ($\sigma_n$) is not significantly greater than the respective of the positive interest adjusted basis ($\sigma_p$). Respectively, the alternative hypothesis ($H_1$) postulates that the standard deviation of the negative interest adjusted basis is (statistically significantly)
higher relative to the positive interest adjusted basis. Hence, we are dealing with a one-tailed version:

\[ H_0 : \sigma_n = \sigma_p \]
\[ H_1 : \sigma_n > \sigma_p \quad \text{Upper one tailed test} \]

The decision rule implies that for a level of significance (\(\alpha=5\%\)) the null will be accepted if the F statistic is lower than the critical value \(F_0 (F < F_0)\).

### Table 5.1: Evaluation of the Interest adjusted basis with regard to Henry Hub natural gas prices, Nov. ’93-Jun. ’09

<table>
<thead>
<tr>
<th>Holding Period</th>
<th>1-month</th>
<th>3-months</th>
<th>6-months</th>
<th>12-months</th>
</tr>
</thead>
<tbody>
<tr>
<td>Positive</td>
<td>2250</td>
<td>2740</td>
<td>2710</td>
<td>2024</td>
</tr>
<tr>
<td>Negative</td>
<td>1640</td>
<td>1150</td>
<td>1180</td>
<td>1760</td>
</tr>
<tr>
<td>Total</td>
<td>3890</td>
<td>3890</td>
<td>3890</td>
<td>3784</td>
</tr>
<tr>
<td><strong>Mean Value</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Positive</td>
<td>0.0478</td>
<td>0.0974</td>
<td>0.1394</td>
<td>0.1837</td>
</tr>
<tr>
<td>Negative</td>
<td>-0.0419</td>
<td>-0.090</td>
<td>-0.1454</td>
<td>-0.1473</td>
</tr>
<tr>
<td>Total</td>
<td>0.0103</td>
<td>0.0421</td>
<td>0.0534</td>
<td>0.0342</td>
</tr>
<tr>
<td><strong>Standard deviation</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Positive</td>
<td>0.0668</td>
<td>0.1138</td>
<td>0.1398</td>
<td>0.1200</td>
</tr>
<tr>
<td>Negative</td>
<td>0.0478</td>
<td>0.1188</td>
<td>0.1458</td>
<td>0.1249</td>
</tr>
<tr>
<td>Total</td>
<td>0.0794</td>
<td>0.1482</td>
<td>0.1965</td>
<td>0.2189</td>
</tr>
<tr>
<td><strong>F-test of the standard deviations of the population</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>( F_{n_1-1,n_2-1} )</td>
<td>1.14</td>
<td>1.09</td>
<td>1.09</td>
<td>1.08</td>
</tr>
<tr>
<td>( F_{1,n_2-1} )</td>
<td>1.08</td>
<td>1.08</td>
<td>1.08</td>
<td>1.07</td>
</tr>
</tbody>
</table>

* For a holding period of 12 months the data set from November ’93 until March ’09

By applying the preceding rationale in Henry Hub natural gas prices we conclude that the standard deviation of the negative adjusted basis is statistically higher than the respective positive basis. Thus, according to the theory’s prediction in the presence of adequate

\[ F = \frac{s_1^2}{s_2^2} \]

An F-test is used to examine if the standard deviations between two populations are equal. If \(s_1^2\) and \(s_2^2\) are the variances of two independent random samples of \(n_1\) and \(n_2\) size respectively, then the sampling distribution of the test statistic is approximately F distributed with \(n_1\) (numerator) and \(n_2\) (denominator) degrees of freedom. The test can be two-tailed or one-tailed. The two-tailed version tests against the alternative that the standard deviations are not equal. The one-tailed version test in one direction, i.e., the standard deviation from the first population is either higher than or less than the second population’ standard deviation. The F hypothesis test is defined as:

\[ H_0 : \sigma_1^2 = \sigma_2^2 \quad \text{against} \]
\[ H_1 : \sigma_1^2 < \sigma_2^2 \quad \text{a lower one tailed test} \]
\[ H_1 : \sigma_1^2 > \sigma_2^2 \quad \text{an upper one tailed test} \]
\[ H_1 : \sigma_1^2 \neq \sigma_2^2 \quad \text{for a two tailed test} \]

The test statistic \(F\) is the ratio between the sample variances. According to the literature the more this ratio deviates from unity the stronger is the evidence of unequal population variances. For a statistical level of significance \(\alpha\) the null hypothesis is rejected accordingly to the cases presented in the preceding parentheses under the convention that \(F_{\alpha}\) is the upper critical value from the distribution and \(F_{1-\alpha}\) is the lower critical value.
reserves, large inventory responses to shocks will cause approximately the same deviations in the spot and futures natural gas prices, whereas in periods of low inventory levels, smaller responses to shocks will have a larger effect in the commodity’s spot prices relatively to the futures prices.

Furthermore, the relationship between spot and futures prices at the date of the contract’s expiration (the nearby contracts) is examined. Even though, during the contract’s trading period, futures prices can be higher or lower than spot prices, in many commodities –especially the storable- the price of the futures contract should converge to the spot price, as the delivery period of the commodity approaches.

**Figure 5.3: Henry Hub natural gas futures and spot prices at the last trading day of monthly futures contracts**

If this is not the case, then opportunities for risk-less profits emerge. Figure 5.3, shows the relationship between the pair of prices at the date of the futures contracts expiration, i.e., three business days before the last trading month. Futures and spot Henry Hub prices tend to converge at maturity with the average difference being at approximately 10 cents per MBtus for the period examined. Furthermore, convergence in the pairing of prices ($7.5 per MBtus) is recorded in April 2007, whereas the highest price difference ($2,6 per Mbtus) between the two prices is recorded in November of 2004.

In conclusion, it can be said that the futures and the concurrent spot prices for the Henry Hub natural gas case, exhibit similarities in their patterns; a fact which is related to the storable nature of the commodity. Storability enables inter-temporal arbitrage opportunities, through which, changes in the futures and spot prices are related.
In this way, the price level observed at the spot natural gas market can have a predictive value for the natural gas futures price. In contrast, a less obvious relationship is recorded between futures and contemporaneous PJM prices. Since electricity is not effectively storable at large scale, arbitrage opportunities on the specific commodity between two different periods are difficult to emerge. However, according to our proposition the basis of electricity can have an indirect relationship through the fuel used to generate it. In the following section we test that proposition on PJM and Palo Verde electricity prices, assuming natural gas to be the marginal fuel.

### 5.3 Empirical results of the proposition

The proposition (developed in chapter three) introduces a relationship between the basis of electricity and the convenience yield of the marginal fuel used in power generation. The proposition is a linear relationship between the dependent variable (the basis) and the independent variables assumed.

It is important to underline that the empirical work conducted in the following sections does not attempt to model the basis or other factors observed in the power sector. Instead, the intention is to test the theoretical proposal developed with respect to the principles of storage theory, according to the datasets obtained.

From that perspective, a potential critique on the proposition relates to the disadvantage of missing variables (for instance electricity grid flow constraints, emissions rates etc.), which implies that the explanatory power can be weak. We argue that the lack of additional explanatory variables is mainly due to the examination of the proposed relationship according
Chapter 5: Empirical analysis - The case of natural gas in power generation

...to the implications of the storage theory and the variables influencing the basis. Even though, additional assumptions could be possibly made, it should not be undermined that the availability of complete and reliable data is a disadvantage. In addition, the nature of electricity, compared to other commodities, adds restrictions in the proposition that the indirect type of storage in the power industry can be approached through the implications of the storage theory.

Taking into consideration those characteristics, we are interested in testing whether a principal component of the theory of storage, i.e., the difference between the futures price and the contemporaneous spot electricity prices, is linearly and negatively related to the level of the (marginal) fuel's net carrying costs, by taking also in consideration the demand for power according to the degree days variables.

In this chapter, we assume that natural gas is the marginal fuel and respectively we test the impact of its carrying charges on peak electricity prices. Natural gas is, according to FERC, the energy resource used in power generation during the hours of higher demand for power in Arizona, California and the regions served by the PJM Interconnection. In order to test the theoretical proposition we use data (spot and futures prices) from the PJM Interconnection and the Palo Verde trading hub. The empirical specification of the theoretical proposition is revised as follows:

\[
\text{Basis}_t^{\text{Electricity}} = \beta_0 + \beta_1 \text{Marginal Fuel}_t \times r_t + \beta_2 \text{NG}_t^{\text{Marginal Fuel}} + \beta_3 \text{HDD}_t + \beta_4 \text{CDD}_t + \epsilon_t \quad (5.4)
\]

where \( \beta_i \) i=0,1,..,4 are the regression parameters to be estimated and \( \epsilon_t \) denotes the error term of the regression. The constant term \( \beta_0 \) describes, by assumption, the fixed transmission costs, \( \beta_1 \) is the estimate of the financial cost multiplied by the heat rate (heat rates of units are regarded as constants for the purpose of calculation in the natural gas case) while \( \beta_2 \) refers to the coefficient of the net of storage convenience yield in which a measurement error\(^{43}\) is incorporated. Finally, \( \beta_3 \) and \( \beta_4 \) are the regression estimates of heating and cooling degree-days, which are variables of weather-related energy use.

Equation (5.4) is a linear regression of four regressors (explanatory variables) and a constant; hence five parameters are estimated using the ordinary least squares (OLS) method. The OLS estimator \( \hat{\beta} \) is a linear and unbiased estimator with the minimum variance among the class of all estimators of its class, a property which is known as the

\(^{43}\) The net of storage convenience estimation as it was introduced in section 4.10 ignores potential pricing residuals stemming from data approximations. The existence of measurement errors have been recorded in the literature in the estimation of yield curves and interest rates. Under the specific presumption the estimation of the net of storage convenience yield can be of the form:

\[
\text{NZ}_t^{\text{Marginal Fuel}} = S_t - F_t e^{-T_0(T-t)/365} = \theta (\text{SC}_t^{\text{Marginal Fuel}} - Z_t^{\text{Marginal Fuel}})
\]

The above relationship implies that

\[
\frac{1}{\theta} \text{NZ}_t^{\text{Marginal Fuel}} = S_t - F_t e^{-T_0(T-t)/365}
\]

Hence, the parameter \( \beta_2 \) denotes \( b \times HR \times \alpha \) where \( \alpha = 1/\theta \).
Chapter 5: Empirical analysis - The case of natural gas in power generation

Gauss-Markov. Due to that reason, \( \hat{\beta} \) is also known as the Best Linear Unbiased estimator. This property implies that \( \hat{\beta} \) is a linear (each of the components of the vector) function of the independent variables, its expected value is equal to the corresponding element of the true \( \beta \) (i.e., \( E(\hat{\beta}) = \beta \)), while it exhibits the lowest variance among all efficient estimators.

However, estimation of the slope coefficients according to the OLS method presumes that the stochastic process is stationary. In the presence of non-stationary parameters, the use of the OLS method can lead to invalid estimates. Granger and Newbold (1974) have shown that such estimates result from “spurious regressions”, i.e., regressions of high \( R^2 \) values and t-ratios, but without economic meaning since the standard t and F statistic procedures are invalid. For that purpose, as a first step the order of integration of the regressand and the regressors as well should be specified.

In chapter 4, the Augmented Dickey-Fuller, Phillips-Perron and KPSS tests were employed in order to examine the stationarity process of the series incorporated in (5.4). According to the results of the tests, the basis of the PJM prices is stationary – as the difference between the futures and spot electricity prices, and the same applies for the Henry hub convenience yield and the HDD-CDD parameters.

In contrast, the variable \( r_t \times S_{i, Marginal \ Fuel} \) that represents the interest foregone from withholding inventory of the commodity (the fuel in our case) is non-stationary44 since it is the product of two series, the nominal interest rate and the spot gas price, with a unit root. Hence, from an econometric perspective a technical issue arises by the time a stationary dependent variable is, according to the proposed relationship, linearly related to a non-stationary time series. The latter, is a matter of integration or growth accounting implying that the right and the left hand sides of the equation should be of the same order of integration or trend.

It follows that conventional measures included in an OLS regression will not have the usual interpretation. Due to that reason, alternatives should be examined on how to overcome that disadvantage. Those are summarized in the following cases:

i) Consider short trading periods,

ii) Run the regression including the I(1) variable and then test the stationarity of the residuals and finally,

iii) Omit the I(1) variable from the regression as long as a bias problem does not emerge.

Case (i) arises from the assumption employed by Botterud, Kristiansen & Ilic (2009) for short-time holding periods, between one to six weeks of futures trading, which imply that

44 See the appendix of chapter 4, Tables 4.19 and 4.20
interest rates are in practice zero. Subsequently, they derive the convenience yield\textsuperscript{45} as the fraction of the spot over the futures prices. In our case, it stems that \((r_t \times S_{\text{Marginal Fuel}}^t)\) has a zero value and consequently is left out of the regression. In this occasion, however, only futures contracts with the closest delivery (in fact monthly futures contracts) are considered in order to be consistent with the “short time trading” presumption.

On the other hand, in the presence of non-stationary variables a linear combination known as cointegration should be pursued. Cointegration, which is the combination of two or more integrated series is a method for correcting hypotheses concerning the relationship between variables with unit roots. A cointegration relationship implies that the variables included in the regression are of the same order of integration. In our case, however, we examine a regression where the dependent variable is \(I(0)\) and the explanatory variables are either \(I(0)\) or \(I(1)\). The absence of an additional \(I(1)\) variable, according to the assumptions made in the theoretical part, implies that a co-integrating relationship cannot exist. The alternative therefore, is to examine the stationarity properties of the residuals in the regression where the \(I(1)\) has been incorporated as well. The existence of \(I(0)\) disturbances should be an indication that the proposed relationship operates in a satisfactory manner\textsuperscript{46}.

Finally, case (iii) suggests that a possible resolution may arise from the omission of a variable in the regression –the \(I(1)\) variable in particular, under the condition that specific requirements are met that can be summarized in the following example with respect to a bivariate regression:

\[
Y_t = \beta_0 + \beta_1 X_{1t} + \beta_2 X_{2t} + \varepsilon_t \tag{5.4}
\]

If a regressor (for instance \(X_{2t}\)) is excluded then the estimated relationship will be of the form:

\[
Y_t = \beta_0 + \beta_1 X_{1t} + u_t \quad \text{where} \quad u_t = \beta_2 X_{2t} + \varepsilon_t \tag{5.5}
\]

In general, this approach shows that by omitting regressors which have an impact on the dependent variable (i.e., \(\beta_2\) is non-zero in the particular situation) will bias the OLS estimates of the remaining regressors. The bias can only be avoided if only the omitted regressor is not correlated with those included in the regression. As far as the proposed relationship is concerned, the preceding rationale implies that if the \(I(1)\) variable \((r_t \times S_{\text{Marginal Fuel}}^t)\) is uncorrelated with the rest variables of the equation, then by omitting it the estimated results will not be biased.

Finally, the OLS estimates of regression (5.4) are based on the Newey-West covariance matrix estimator, procedure which is met in many empirical studies with respect to electricity

\textsuperscript{45} The convenience yield in this study is estimated from power prices. See literature review in chapter 2.
\textsuperscript{46} This approach is analyzed in Baffes (1996) where a regression on a metal export supply model is considered in which the dependent variable is \(I(0)\), while the explanatory variables are \(I(1)\).
prices. The Newey-West approach is undertaken because the error term exhibits serial correlation and heteroskedasticity (mainly to larger price fluctuations relatively to other commodity markets) implying that the OLS estimators, even though they remain unbiased, consistent and asymptotically normally distributed they cease to be efficient. The latter implies that the standard errors are misspecified and consequently the confidence intervals and the hypothesis testing are deceptive. To overpass it Newey and West propose a variance-covariance matrix, which remains consistent in the presence of autocorrelation and heteroskedasticity by incorporating standard errors of OLS estimates adjusted for autocorrelation.

5.3.1 The case of PJM peak electricity prices

Table 5.2 shows the estimates from the regression of the basis for monthly PJM futures contracts (Case I). The regression coefficient for the convenience yield on natural gas is negative and statistically significant.

Table 5.2: PJM Inter/ction-estimated parameters proposed relationship, (Case I)

<table>
<thead>
<tr>
<th>Dependent Variable: Basis</th>
<th>1-pos</th>
</tr>
</thead>
<tbody>
<tr>
<td>Included Observations: 1530</td>
<td></td>
</tr>
<tr>
<td>Explanatory Variables</td>
<td></td>
</tr>
<tr>
<td>Constant</td>
<td>1.458</td>
</tr>
<tr>
<td>(0.0000)</td>
<td></td>
</tr>
<tr>
<td>$N_{\text{fuel}}^{\text{natural}}$ (Henry Hub Natural Gas)</td>
<td>-4.457</td>
</tr>
<tr>
<td>(0.0000)</td>
<td></td>
</tr>
<tr>
<td>HDD</td>
<td>-1.312</td>
</tr>
<tr>
<td>(0.0000)</td>
<td></td>
</tr>
<tr>
<td>CDD</td>
<td>-2.116</td>
</tr>
<tr>
<td>(0.0000)</td>
<td></td>
</tr>
<tr>
<td>Sample period</td>
<td></td>
</tr>
<tr>
<td>(Daily observations Monday-Friday)</td>
<td>Jan.'03-May '09</td>
</tr>
<tr>
<td>Adj-R²</td>
<td>0.152</td>
</tr>
<tr>
<td>Prob. (F-Statistic)</td>
<td>0.0000</td>
</tr>
</tbody>
</table>

The numbers in parentheses refer to the probability values.

This indicates that when the market participants in the power sector expect that the supplies of the fuel are adequate to meet demand from households and the power industry as well, the futures prices of electricity will tend to be higher compared to the spot price. Respectively, if the fuel’s reserves are lower, which is observed during the periods of higher demand, an increase in the spot price due to higher fuel cost is more probable to occur, leading to a negative basis of the electricity prices.

---


48 The probability value (p-value) indicates the probability of committing a Type I error i.e., the probability of rejecting the true hypothesis. Particularly, the p value is defined as the lowest significance level at which a null hypothesis can be rejected.
Table 5.3: PJM Interconnection-estimated parameters of the proposed relationship, (Case II)

<table>
<thead>
<tr>
<th>Dependent Variable: Basis</th>
<th>1-pos</th>
<th>3-pos</th>
<th>6-pos</th>
<th>12-pos</th>
</tr>
</thead>
<tbody>
<tr>
<td>Included Observations</td>
<td>1530</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Explanatory Variables</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Constant</td>
<td>1.367</td>
<td>3.096</td>
<td>1.641</td>
<td>1.882</td>
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<tr>
<td>(0.0000)</td>
<td>(0.0000)</td>
<td>(0.0000)</td>
<td>(0.0000)</td>
<td></td>
</tr>
<tr>
<td>(S^t) (Marginal Fuel)</td>
<td>(-0.534)</td>
<td>1.098</td>
<td>(-5.604)</td>
<td>1.571</td>
</tr>
<tr>
<td>(0.2439)</td>
<td>(0.0653)</td>
<td>(0.1869)</td>
<td>(0.0107)</td>
<td></td>
</tr>
<tr>
<td>(NZ^t) (Marginal Fuel)</td>
<td>(-4.419)</td>
<td>(-2.854)</td>
<td>(-0.842)</td>
<td>(-6.996)</td>
</tr>
<tr>
<td>(0.0000)</td>
<td>(0.0030)</td>
<td>(0.0923)</td>
<td>(0.0000)</td>
<td></td>
</tr>
<tr>
<td>HDD</td>
<td>(-1.224)</td>
<td>(-2.459)</td>
<td>(-1.331)</td>
<td>(-1.595)</td>
</tr>
<tr>
<td>(0.0000)</td>
<td>(0.0000)</td>
<td>(0.0000)</td>
<td>(0.0000)</td>
<td></td>
</tr>
<tr>
<td>CDD</td>
<td>(-3.006)</td>
<td>(-5.315)</td>
<td>(-2.372)</td>
<td>(-4.028)</td>
</tr>
<tr>
<td>(0.0000)</td>
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<td>(0.0000)</td>
<td>(0.0000)</td>
<td></td>
</tr>
</tbody>
</table>

Sample period


Adj-R² | 0.16 | 0.37 | 0.27 | 0.39 |

Prob. (F-Statistic) | 0.0000 | 0.0000 | 0.0000 | 0.0000 |

Accordingly, by implementing the regression in which the \((r_t \times S^t)\) variable is incorporated (case II), it stems that the estimates of \(NZ^t\) are negative and statistically significant for the contract maturities encountered. The highest negative value is recorded for futures contracts of longer maturity (12 months) in which case, a change in the natural gas’ convenience yield by 1% is associated with a change of the opposite sign by -7.0% to the basis of PJM electricity prices, under the condition that the remaining parameters remain constant. This finding implies that the level of the fuel’s inventory has a higher impact on electricity futures and spot prices when the delivery of the commodity is deferred.

On the other hand, the estimated coefficient of \((r_t \times S^t)\) has no statistical significance on the proposed relationship, except of the longer maturity (12 months). This finding may indicate that transaction costs have a minor effect in the operation of a power plant, at least in the short term. In contrast, for higher maturities such as a year, commodity prices and interest rates are expected to exhibit similar trend taking into consideration that the level of the Consumer Price Index —and respectively the inflation, affects the level of the interest rate.

In contrast, the regression coefficients of cooling and heating degree-days have explanatory power (p-value is zero), which implies the effect of both higher (increased CDH) and low temperatures (increased HDH) on electricity prices during the peak hours of the day, as the demand curve moves towards the convex part of the supply side of the power market. The
negative sign of the estimate suggests that changes in demand leads to higher spot prices at a level above than the respective of the futures price and respectively to a negative basis.

In addition, by testing the stationarity of the residuals it follows that the estimated regression disturbances are I(0), according to the Augmented Dickey-Fuller, the Philips-Perron and the KPSS tests (Table 5.4). This feature is explained by the fact that the I(1) parameter incorporated in the regression have statistically in-significant effect in the regression, based on heteroskedasticity and autocorrelation consistent standard errors.

<table>
<thead>
<tr>
<th>Case</th>
<th>1-pos</th>
<th>3-pos</th>
<th>6-pos</th>
<th>12-pos</th>
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<tbody>
<tr>
<td>ADF</td>
<td>I(0)</td>
<td>I(0)</td>
<td>I(0)</td>
<td>I(0)</td>
</tr>
<tr>
<td></td>
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<td>I(0)</td>
<td>I(0)</td>
<td>I(0)</td>
<td>I(0)</td>
</tr>
<tr>
<td>KPSS</td>
<td>I(0)</td>
<td>I(0)</td>
<td>I(0)</td>
<td>I(0)</td>
</tr>
<tr>
<td></td>
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<td>I(0)</td>
<td>I(0)</td>
<td>I(0)</td>
<td>I(0)</td>
</tr>
</tbody>
</table>

Notes: *The null (the series is stationary) is accepted at α=1% and 5%, **The null is accepted at α=1%. See the appendix of the chapter for the test statistics of the ADF, PP and KPSS tests.

Finally, the third case of the regression estimation is examined, which is based on the presumption that the I(1) variable can be excluded if an omitted problem does not arise. The exclusion of the variable can be justified in case \( r_i \times S_i^{\text{Marginal Fuel}} \) is not related with each of the remaining variables (i.e., the convenience yield and the heating / cooling degree-days variables). It can be argued that bias due to the exclusion of the variable from the regression is less likely to occur, since the omitted variable has an insignificant t-statistic in the regression. Alternatively, by regressing the I(1) variable on each of the variables of the regression, the OLS estimates are either not statistically significant (p-value>0.05) or the coefficients estimates are near zero.
Table 5.5: PJM Interconnection-estimated parameters of the proposition (Case III)

<table>
<thead>
<tr>
<th>Dependent Variable: Basis</th>
<th>3-pos</th>
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<th>12-pos</th>
</tr>
</thead>
<tbody>
<tr>
<td>Included Observations: 1530</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Explanatory Variables</th>
<th>3-pos</th>
<th>6-pos</th>
<th>12-pos</th>
</tr>
</thead>
<tbody>
<tr>
<td>Constant</td>
<td>3.277</td>
<td>1.534</td>
<td>2.156</td>
</tr>
<tr>
<td>(0.0000)</td>
<td>(0.0000)</td>
<td>(0.0000)</td>
<td></td>
</tr>
<tr>
<td>N_{LT}^f (Henry Hub Nat. Gas)</td>
<td>-2.837</td>
<td>-0.951</td>
<td>-6.743</td>
</tr>
<tr>
<td>(0.0012)</td>
<td>(0.0599)</td>
<td>(0.0000)</td>
<td></td>
</tr>
<tr>
<td>HDD</td>
<td>-2.435</td>
<td>-1.336</td>
<td>-1.586</td>
</tr>
<tr>
<td>(0.0000)</td>
<td>(0.0000)</td>
<td>(0.0000)</td>
<td></td>
</tr>
<tr>
<td>CDD</td>
<td>-5.258</td>
<td>-2.409</td>
<td>-3.928</td>
</tr>
<tr>
<td>(0.0000)</td>
<td>(0.0000)</td>
<td>(0.0000)</td>
<td></td>
</tr>
<tr>
<td>Sample period</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>(Daily observations Monday-Friday)</td>
<td>Jan. '03-May '09</td>
<td>Jan. '03-May '09</td>
<td>Jan. '03-May '09</td>
</tr>
<tr>
<td>Adj-R²</td>
<td>0.36</td>
<td>0.26</td>
<td>0.38</td>
</tr>
<tr>
<td>Prob(F-statistic)</td>
<td>0.0000</td>
<td>0.0000</td>
<td>0.0000</td>
</tr>
</tbody>
</table>

The estimated parameters from case III regression (Table 5.5) offer similar results to the previous case examined for contracts of three, six and twelve months to maturity (exclusion of monthly futures contacts is the case I considered earlier when the assumption of zero interest rate is made). The basis on PJM electricity prices is negatively related to the convenience yield emerging from the Henry Hub spot and futures natural gas prices for the holding periods under consideration, whereas the same applies for the remaining regressors of the relationship.

Figure 5.5: Electricity basis-Henry Hub net convenience yield (monthly futures)

In addition, the adjusted $R^2$—the interpretation of the fraction of the variation attributed to the variation in the explanatory variables, increases with the maturities examined,
observation which implies a better fit of the data for trading periods between six and twelve months.

In summary, the proposed relationship indicates that in periods of higher (marginal) fuel inventory, convenience yield should fall (according to the theory of storage) leading futures prices at the PJM Interconnection at a higher level relatively to the contemporaneous spot prices (i.e., a positive basis). On the other hand, an increase in the convenience yield of the fuel should be associated to a decline in the fuel’s storage supplies. In this case, increased fuel price that is often recorded due to the tight supply, should have an impact on the spot PJM prices during the peak hours of the day. This argument assumes that gas power plants are mainly dispatched at the peak hours, thus they affect the convex part of the supply curve in the specific market.

In accordance to the previous findings, Figure 5.5 illustrates periods where the negative relationship between the basis of PJM prices and the Henry Hub net of storage convenience yield is more pronounced. For example, in January and February of 2007, natural working gas inventory fell at 1,600,000 MCF (when during the specific year average inventory was at 2,600,000 MCF), leading the estimated convenience yield of natural gas to a substantial increase and the PJM basis to a negative level. In contrast, in November 2004 when working gas inventory was unexpectedly high for the season (3,240,000 MCF), the net of storage convenience yield fell and the PJM futures prices was higher than the spot price by approximately 10 dollars per MWh. In the following section, we use the Palo Verde spot and futures prices as a case study, assuming as well, that natural gas is the marginal fuel in power generation.

5.3.2 The case of the Palo Verde peak electricity prices

Palo Verde is the most active trade power hub in the western United States. It is located close to several existing natural gas pipelines, making it a desirable location for merchant power plants. According to the Western Systems Coordinating Council (WSCC)\textsuperscript{49}, Palo Verde high voltage switchyard hub is considered a major trading point of electricity in Southwest power market. Along with the PJM Interconnection, the Palo Verde hub is a trading point within the WSCC that the NYMEX offers electricity futures contracts.

As far as the proposed relationship is concerned with respect to the Palo Verde and the Henry Hub prices, Table 5.6 shows the regression estimates of the near-by trading period in which case, a zero interest rate is assumed and subsequently \((R_t \times S^\text{Marginal Fuel}_t)\) is not considered. According to this assumption, the basis of the Palo Verde electricity prices is

\textsuperscript{49} WSCC is an operating and planning organization that aims to provide a reliable and adequate electric-power system for Western United States, Canada and Mexico.
negatively related to the Henry Hub natural gas convenience yield, however, the p-value indicates that the data falsify the respective hypothesis.

Table 5.6: Palo Verde electricity hub - estimated parameters of the proposed relationship, (Case I)

<table>
<thead>
<tr>
<th>Dependent Variable: Basis</th>
<th>1-pos</th>
</tr>
</thead>
<tbody>
<tr>
<td>Included Observations: 1530</td>
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</tr>
<tr>
<td>Explanatory Variables</td>
<td></td>
</tr>
<tr>
<td>Constant</td>
<td>1.896</td>
</tr>
<tr>
<td>(Henry Hub Nat. Gas)</td>
<td>(0.0000)</td>
</tr>
<tr>
<td>HDD</td>
<td>-0.933</td>
</tr>
<tr>
<td>(0.0846)</td>
<td></td>
</tr>
<tr>
<td>CDD</td>
<td>-0.012</td>
</tr>
<tr>
<td>(0.0123)</td>
<td></td>
</tr>
</tbody>
</table>

Sample period (Daily observations Monday-Friday) Aug. ’04-Sep. ’08

Adj-R² 0.22

Prob (F-Statistic) 0.000

* The numbers in parentheses are the probability values

It order to examine whether an impact by the fuel’s supply for inventory is supported in the Palo Verde basis for higher than a month trading periods, the interest foregone parameter is taken into consideration (Case II). Results in Table 5.7 provide evidence in favour of the proposition for contracts of higher than three months to maturity. The estimates show that a percentage change of 1% in the convenience yield is associated with a change between -2% and -3.5% in the basis of the Palo Verde prices. Similarly to the PJM peak prices, the estimate of the convenience yield with regard to Henry Hub futures contracts is higher for the trading period of twelve months.

This result can be associated with the proposition of Brooks and El-Keib (1998) arguing that for short trading periods the main factors that drive the electricity prices are potential interruption of a power unit’s operation and weather conditions that lead to unexpected shifts of demand. The demand side in particular, is considered the most important determinant for the variation of electricity prices. In contrast, in medium trading periods (i.e., from some months up to a year) electricity prices are primarily determined by the fuel cost, the change in retail demand (medium and small consumers) and the expansion of load.
Table 5.7: Palo Verde electricity hub-estimated parameters of the proposed relationship, (Case II)

<table>
<thead>
<tr>
<th>Dependent Variable: Basis</th>
<th>1-pos</th>
<th>3-pos</th>
<th>6-pos</th>
<th>12-pos</th>
</tr>
</thead>
<tbody>
<tr>
<td>Included Observations: 1530</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Explanatory Variables</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Constant</td>
<td>2.302</td>
<td>2.661</td>
<td>2.941</td>
<td>1.541</td>
</tr>
<tr>
<td>(0.0000)</td>
<td>(0.0000)</td>
<td>(0.0000)</td>
<td>(0.0008)</td>
<td></td>
</tr>
<tr>
<td>$S_{\text{Marginal Fuel}}$ (Henry Hub Nat. Gas)</td>
<td>-2.364</td>
<td>-4.208</td>
<td>-1.456</td>
<td>1.859</td>
</tr>
<tr>
<td>(0.0376)</td>
<td>(0.1657)</td>
<td>(0.8751)</td>
<td>(0.0586)</td>
<td></td>
</tr>
<tr>
<td>$NZ_{\text{Marginal Fuel}}$ (Henry Hub Nat. Gas)</td>
<td>-0.969</td>
<td>-2.361</td>
<td>-2.357</td>
<td>-3.473</td>
</tr>
<tr>
<td>(0.5886)</td>
<td>(0.0053)</td>
<td>(0.0147)</td>
<td>(0.0000)</td>
<td></td>
</tr>
<tr>
<td>HDD</td>
<td>-0.723</td>
<td>-0.843</td>
<td>-1.959</td>
<td>-1.594</td>
</tr>
<tr>
<td>(0.1442)</td>
<td>(0.0515)</td>
<td>(0.0006)</td>
<td>(0.0000)</td>
<td></td>
</tr>
<tr>
<td>CDD</td>
<td>-0.627</td>
<td>-1.321</td>
<td>-1.707</td>
<td>-0.812</td>
</tr>
<tr>
<td>(0.0208)</td>
<td>(0.0000)</td>
<td>(0.0000)</td>
<td>(0.0076)</td>
<td></td>
</tr>
</tbody>
</table>

Sample period
(Daily observations Monday-Friday) Jan. '03-May '09 Jan. '03-May '09 Jan. '03-May '09 Jan. '03-May '09

Adj-R² | 0.23 | 0.43 | 0.42 | 0.38 |
Prob (F-Statistic) | 0.000 | 0.000 | 0.000 | 0.000 |

In particular, for the Palo Verde electricity prices the inventory level of the marginal fuel, in terms of the convenience yield, does not offer an economic meaning in the case of monthly contracts since the coefficient in the regression is statistically insignificant.

Table 5.8: Palo Verde electricity hub, unit root tests of the residuals from the Case II regression

<table>
<thead>
<tr>
<th>Case</th>
<th>1-pos</th>
<th>3-pos</th>
<th>6-pos</th>
<th>12-pos</th>
</tr>
</thead>
<tbody>
<tr>
<td>ADF</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>1. No constant term and no linear trend</td>
<td>I(0)</td>
<td>I(0)</td>
<td>I(0)</td>
<td>I(0)</td>
</tr>
<tr>
<td>2. Constant term but not a linear trend</td>
<td>I(0)</td>
<td>I(0)</td>
<td>I(0)</td>
<td>I(0)</td>
</tr>
<tr>
<td>3. Constant term and a deterministic linear trend</td>
<td>I(0)</td>
<td>I(0)</td>
<td>I(0)</td>
<td>I(0)</td>
</tr>
<tr>
<td>Philips-Peron</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>1. No constant term and no linear trend</td>
<td>I(0)</td>
<td>I(0)</td>
<td>I(0)</td>
<td>I(0)</td>
</tr>
<tr>
<td>2. Constant term but not a linear trend</td>
<td>I(0)</td>
<td>I(0)</td>
<td>I(0)</td>
<td>I(0)</td>
</tr>
<tr>
<td>3. Constant term and a deterministic linear trend</td>
<td>I(0)</td>
<td>I(0)</td>
<td>I(0)</td>
<td>I(0)</td>
</tr>
<tr>
<td>KPSS</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>1. Intercept</td>
<td>I(1)</td>
<td>I(0)</td>
<td>I(0)</td>
<td>I(0)</td>
</tr>
<tr>
<td>2. Trend and intercept</td>
<td>I(0)</td>
<td>I(0)</td>
<td>I(0)</td>
<td>I(0)</td>
</tr>
</tbody>
</table>

Moreover, stationarity tests employed for the residuals indicate an I(0) order in the case of higher holding periods, which is related to the fact that the interest payment on natural gas variable (i.e., the I(1) parameter is an integrated of order 1 series) has insignificant t-statistics. With respect to the estimates of cooling and heating degree-days the effect of
higher temperatures (increased CDH) is more pronounced in the Palo Verde electricity prices during the peak hours of the day compared to the PJM case.

Table 5.9: Palo Verde electricity hub-estimated parameters of the proposed relationship, (Case III)

<table>
<thead>
<tr>
<th>Dependent Variable: Basis</th>
<th>3-pos</th>
<th>6-pos</th>
<th>12-pos</th>
</tr>
</thead>
<tbody>
<tr>
<td>Included Observations: 1530</td>
<td>2.323</td>
<td>2.899</td>
<td>2.253</td>
</tr>
<tr>
<td>Explanatory Variables</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Constant</td>
<td>(0.0000)</td>
<td>(0.0000)</td>
<td>(0.0000)</td>
</tr>
<tr>
<td>$N_{\text{Henry Hub Nat. Gas}}$</td>
<td>-2.645</td>
<td>-2.421</td>
<td>-2.556</td>
</tr>
<tr>
<td>HDD</td>
<td>-0.799</td>
<td>-1.949</td>
<td>-1.665</td>
</tr>
<tr>
<td>CDD</td>
<td>-1.317</td>
<td>-1.714</td>
<td>-0.967</td>
</tr>
<tr>
<td>Sample period</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>(Daily observations Monday-Friday)</td>
<td>Jan. '03-May '09</td>
<td>Jan. '03-May '09</td>
<td>Jan. '03-May '09</td>
</tr>
<tr>
<td>Adj-R$^2$</td>
<td>0.42</td>
<td>0.42</td>
<td>0.39</td>
</tr>
<tr>
<td>Prob (F-Statistic)</td>
<td>0.000</td>
<td>0.000</td>
<td>0.000</td>
</tr>
</tbody>
</table>

* The numbers in parentheses are the probability values
Appendix

Heteroskedasticity and Autocorrelation Consistent (HAC) standard errors

Even if heteroskedasticity is assumed, OLS is still unbiased and consistent but the standard errors are biased.

If the standard errors are biased, the usual $t$ and $F$ statistics cannot be used for drawing inferences, hence OLS estimates are no longer efficient.

The most common response to the (potential) presence of heteroscedasticity of an unknown form is to use a heteroscedastically-robust estimator for the covariance matrix of the regression parameters.

The (variance-) covariance matrix of the OLS estimator is:

$$ \text{Var}(\hat{\beta}|X) = E \left[ (\hat{\beta} - E(\hat{\beta}|X))(\hat{\beta} - E(\hat{\beta}|X))^\prime \right].$$

$$= E \left[ (\hat{\beta} - \beta)(\hat{\beta} - \beta)^\prime \right] = E \left[ (X'X)^{-1} X' e (X'X)^{-1} X' e \right] =$$

$$= E \left[ (X'X)^{-1} X' e e' (X'X)^{-1} X \right] = (X'X)^{-1} X' E[ee'|X] X (X'X)^{-1}$$

According to the finite sample properties of OLS the error variance is spherical, i.e., they have constant variance (homoskedasticity):

$$E[ee'|X] = \sigma^2 I$$

Hence,

$$\text{Var}(\hat{\beta}|X) = (X'X)^{-1} X' \sigma^2 I (X'X)^{-1} = \sigma^2 (X'X)^{-1} X'X (X'X)^{-1}$$

$$\text{Var}(\hat{\beta}|X) = \sigma^2 (X'X)^{-1} \text{ since } X'X (X'X)^{-1} = I$$

However, when heteroskedasticity is present then $E[ee'|X] = \sigma^2 \Omega$

According to the E-views manual the Newey-West estimator $\Omega$ is given by:

$$\Omega = \frac{T}{T-k} \left\{ \sum_{t=1}^{T} u_t^2 x_t x_t' + \sum_{v=1}^{q} \left( \frac{1}{q+1} \right) \sum_{t-v=1}^{T} \left( x_{t,v} u_{t,v} x_{t,v}' + x_{t,v} u_{t,v} u_{t,v}' \right) \right\}$$

where $q$ is the truncation lag, is a parameter representing the number of autocorrelations used in evaluating the dynamics of the OLS residuals $u_t$. 

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Chapter 5: Empirical analysis-The case of natural gas in power generation

Results of the unit root tests on the residuals from the regression of PJM

Table 5.10: Unit root tests of the residuals from the regression of PJM prices on the Henry Hub natural gas convenience yield and the HDD-CDD parameters

<table>
<thead>
<tr>
<th>Case</th>
<th>1-pos</th>
<th>3-pos</th>
<th>6-pos</th>
<th>12-pos</th>
</tr>
</thead>
<tbody>
<tr>
<td>ADF</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>1. No constant term and no linear trend</td>
<td>-18.656</td>
<td>-11.218</td>
<td>-18.602</td>
<td>-16.519</td>
</tr>
<tr>
<td>Philips-Perron</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>1. No constant term and no linear trend</td>
<td>-18.409</td>
<td>-20.474</td>
<td>-18.348</td>
<td>-17.774</td>
</tr>
<tr>
<td>2. Constant term but not a linear trend</td>
<td>-18.403</td>
<td>-20.470</td>
<td>-18.342</td>
<td>-17.769</td>
</tr>
<tr>
<td>KPSS</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>1. Intercept</td>
<td>0.456</td>
<td>0.047</td>
<td>0.638</td>
<td>0.139</td>
</tr>
<tr>
<td>2. Trend and intercept</td>
<td>0.067</td>
<td>0.029</td>
<td>0.065</td>
<td>0.029</td>
</tr>
</tbody>
</table>

Notes: The reported values in the table are the estimated t-statistics and the p-values in the parentheses for the unit root test, according to the three specific situations. The calculated statistics are those reported for the Dickey-Fuller and the Philips-Perron tests. The critical values (for both tests) at 1%, 5% and 10% levels of significance are: for Case 1: -2.57, -1.94 and -1.62; for Case 2: -3.43, -2.86 and -2.57; and for Case 3: -3.96, -3.41 and -3.13 respectively. The KPSS test is based on a Lagrange Multiplier autocorrelation procedure and tests the null hypothesis that the series is stationary against the alternative hypothesis of non-stationarity. The null hypothesis is accepted if the test statistic is lower than the critical value. In the parentheses appear the asymptotic critical values for 1%, 5% and 10% level of significance.

Figure 5.6: Diagrammatic representation of the compounded spot natural gas price by the monthly interest rate

Figure 5.6 depicts the evolution of the compounded spot Henry hub natural gas by the interest rate. The line graph indicates that the specific parameter exhibits small variation. The latter finding may explain the derivation of non-statistically significant parameters in the regression examined.
Chapter 6: Empirical analysis - The case of coal in power generation

6.1 Introduction

Base load generating units have higher capacity factor because they operate at a constant rate in order to supply the grid with electricity. Due to that reason, less expensive energy resources are used in the production process of those units. Coal, despite CO₂ emissions from its production, falls in this category since its lower price variation and the smaller operating costs, compared to natural gas, make it preferable for base load power units.

According to the EIA, power production from natural gas combined cycle was 2.4 times higher than coal fuelled units, while power from natural gas combustion turbines cost 3.8 times as much as coal (2001-2010 average). For that purpose, in many countries (for instance Australia, Greece, USA, Germany etc) most of the supply of baseload power is made through coal power units, whereas in other countries, like France or Spain, other energy resources (e.g. uranium or hydro) are used for the supply of base load power (Figure 6.1).

Figure 6.1: Electricity generation by coal in countries of OECD, 2006

Due to the large share of power generated from coal, the reductions of greenhouse gas emissions have gained considerable attention during the last decades. Among the most effective alternatives to reduce CO₂ emissions is the increase of the generators’ efficiency in order less amount of coal is required for every MWh of electricity produced.

In this section, we follow the same methodology as in the case study between natural gas and peak electricity prices (Chapter 5) in order to examine the proposed relationship with

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50 An electric generating technology in which electricity is produced from otherwise lost waste heat exiting from one or more gas turbines (EIA definition).
respect to the convenience yield from coal futures contracts and the electricity basis for base load prices. For that purpose, historical data from US coal and power markets are used. USA is a major coal exporter with a share of 7% of world production following Australia, Indonesia, China, South Africa and Russia. For instance in 2008, coal exports reached 81 million short tons, relative to 34 million of imports, leading to a net trade surplus of 47 million short tons.

**6.2 Main features of coal**

Coal is classified in four main types, according to its carbon content and the heat energy that produces, i.e., anthracite, bituminous, subbituminous and lignite. Anthracite coal is very rich in carbon and has a heating value slightly higher than bituminous coal. It accounts for less than 0.5% of total coal mined in the United States. Bituminous coal on the other hand, contains less carbon between 45%-85%.

Subbituminous coal has a lower heating value than bituminous coal, between 35%-45% of carbon. That type of coal in the US is at least 100 million years old, representing approximately 40% of total production. Lignite on the other hand, which is mainly burned in power plants, has the lowest energy content. Lignite deposits are relatively young and for that reason they were not subject to high heat or pressure, containing 25%-35% carbon. Approximately 7% of total U.S. coal production comes from lignite mines.

The regions with the largest coal reserves are the Appalachia Coal Region, the Interior Coal Region and the Western Coal Region. More than 1/3 of total production in the United States is produced in the Appalachia Region with coal exports, mainly Central Appalachia bituminous, comprising a significant proportion in the global export market. Central Appalachia coal prices (CAPP) are used as a reference price for eastern coast in the United States and as a benchmark in physical and financial transactions. Respectively, in the Interior Coal Region the largest coal producer state is Texas, accounting for almost 30% of the region's production. However, almost half of the nation's coal production is extracted in the Western Coal Region, mainly in the Powder River Basin along Wyoming, which has the largest surface mines in the world.

**6.3 Coal consumption in the USA**

Coal used for generating electricity accounts for almost 93% of its demand in USA. The fuel is burned in order to heat water in boilers creating steam, which is then used to power turbine generators. It is also used in other industrial sectors, mainly in the steel manufacture and the production of plastics, tar, synthetic fibbers and fertilizers (Figure 6.2). Although coal has been the predominant fuel used in power generation in the U.S. over the last 60 years, its share relatively to other fossil fuels has varied in response to changes in the cost and availability of competing fuels. During the last decade a continuing trend in the power
industry is recorded of substituting coal-fired generation with natural gas generation mainly due to the higher participation of new more efficient technologies (for instance combine cycle).

**Figure 6.2: Coal consumption by sector in the USA, 2008**

![Coal consumption by sector in the USA, 2008](image)

**Source:** EIA

Coal consumption in the power sector exhibits seasonal trends during winter and mainly in the summer. In the July-August bimester the increase in the demand for electricity leads to higher consumption of coal used to generate electricity for air-conditioning. Figure 6.3 shows that coal consumption and net power generation\(^\text{51}\) by coal is inversely related to the level of inventory. For instance, high coal inventory recorded between April and June 2009—an average 195 millions short tons, which is the highest proportion the last three decades, associates with a sharp decline in net power generation at the beginning of the year.

**Figure 6.3: Coal - Consumption, Stocks and Power Generation in the US**

![Coal - Consumption, Stocks and Power Generation in the US](image)

**Source:** EIA

\(^\text{51}\) The gross generation less the electric energy consumed at the generating station.
6.4 The implications of storage theory in coal futures market

The majority of coal traded in the power sector is based on long term contracts with duration of a year or more, accompanied by spot purchases required to supplement demand. Since coal is a bulk commodity, transportation becomes an important determinant of price and availability as well. The majority of coal is transported from the mine to electricity plants by train, barge or trucks. Along with the physical market, NYMEX provides a futures contract with a physical delivery obligation for Central Appalachia coal since July 2001.

Trading of futures contracts implies that coal users can enter the futures market in order to hedge from the commodity’s supply costs. For instance, coal producers can sell futures contracts to secure a sales price for a specified volume they intend to produce. On the other hand, electric utilities can buy coal futures to hedge against rising prices for their base load fuel. Trading in the futures market for coal contract implies that sellers are obliged to deliver and buyers to take possession of CAPP coal per contract specifications, unless the contracts are financially settled before expiration.

Given that coal is a storable commodity it is expected that the implications of the storage theory, such as the inverse relationship between inventory and convenience yield, should hold. In order to examine that presumption, we firstly employ the Fama and French indirect test (1988) based on the variation of spot and futures prices. Assuming constant marginal warehousing costs and higher variation in marginal convenience yield relative to warehousing costs, the sign of the interest-adjusted basis is, according to the approach of Fama and French, a proxy for high (positive interest-adjusted basis) or low (negative interest-adjusted basis) inventory. Table 6.1 shows estimates with regard to Central Appalachia coal prices on a data set from January 2004 until September 2009, based on 1-month, 3-month, 6-month and 12-months to maturity contracts.

<table>
<thead>
<tr>
<th>Holding Period</th>
<th>1-month</th>
<th>3-months</th>
<th>6-months</th>
<th>12-months</th>
</tr>
</thead>
<tbody>
<tr>
<td>Positive</td>
<td>721</td>
<td>853</td>
<td>782</td>
<td>588</td>
</tr>
<tr>
<td>Negative</td>
<td>750</td>
<td>618</td>
<td>689</td>
<td>883</td>
</tr>
<tr>
<td>Total</td>
<td>1471</td>
<td>1471</td>
<td>1471</td>
<td>1471</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Mean Value</th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Positive</td>
<td>0.0149</td>
<td>0.0261</td>
<td>0.0456</td>
<td>0.0104</td>
</tr>
<tr>
<td>Negative</td>
<td>-0.0124</td>
<td>-0.0242</td>
<td>-0.0350</td>
<td>-0.0695</td>
</tr>
<tr>
<td>Total</td>
<td>0.0009</td>
<td>0.0050</td>
<td>0.0079</td>
<td>-0.0016</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Standard deviation</th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Positive</td>
<td>0.0152</td>
<td>0.0200</td>
<td>0.0323</td>
<td>0.0833</td>
</tr>
<tr>
<td>Negative</td>
<td>0.0173</td>
<td>0.0279</td>
<td>0.0327</td>
<td>0.0455</td>
</tr>
<tr>
<td>Total</td>
<td>0.0213</td>
<td>0.0343</td>
<td>0.0517</td>
<td>0.1046</td>
</tr>
</tbody>
</table>

F-test of the standard deviations of the population

<table>
<thead>
<tr>
<th>F-statistic</th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>$F_{5,12-1, n_1-1}$</td>
<td>1.29</td>
<td>1.95</td>
<td>1.03</td>
<td>0.30</td>
</tr>
<tr>
<td>$F_{5,12-1, n_2-1}$</td>
<td>0.88</td>
<td>0.90</td>
<td>0.89</td>
<td>1.10</td>
</tr>
</tbody>
</table>
Estimated mean values and standard deviations for the different signs of the interest adjusted basis are used to perform a difference in standard deviations F-test—similar to that conducted in section 5.2 for the Henry Hub natural gas case\textsuperscript{52}. The standard deviation is (statistically significant) higher for all maturities in the case of negative interest adjusted basis for a level of significance at 5\%. Therefore, the test on spot and futures prices of Central Appalachia coal confirms the prediction of the interest adjust basis proposed by Fama and French.

### 6.5 Determinants of coal price

Coal inventory can be considered a measure of balance between production and demand, and due to that reason it should affect, at least to a certain extent, the magnitude of the commodity’s price fluctuations.

**Figure 6.4: U.S. Coal price and level of stocks -all industries-, Jan. 2003-Jul. 2009**

By comparing those issues it becomes evident that prices adjust to the changes in the level of inventory. For instance, low levels of coal stocks (142 million short tons) between August and October of 2005 led to an increase in coal price at $58 per short ton, which is among the highest prices observed during that year. In contrast, the accumulation of stocks in the mid 2009 due to the economic downturn is followed by a drop in the price at $46 per short ton,

\textsuperscript{52} As mentioned in chapter five, the Fama and French (1988) indirect test postulates that shocks produce more variation in the spot and futures prices when inventory is low (negative interest-adjusted basis). The null hypothesis is that the standard deviation of the negative interest adjusted basis is not significantly greater than that of the positive against the alternative that the standard deviation of the negative interest adjusted basis is statistically significantly higher relative to the positive interest adjusted basis.
level which is similar to that recorded in September 2007. The sudden increase in CAPP prices, which is observed during 2008 is due to the increased rates for transporting the commodity.

On the other hand, the effect of generation costs on wholesale power prices is reflected in the price paid by end consumers. According to ACCCE, electricity rates are usually below the average national retail price in those US states where power generation from coal has larger share.

Figure 6.5: Average retail price of electricity by end user, 2009

(*) Average price of all users (residential, commercial, industrial, transportation)
(**) Mid-Atlantic incorporates the states of New Jersey, New York and Pennsylvania. Respectively, Pacific Contiguous involves Washington and Oregon states
Source: EIA

This is evident in Figure 6.5 which shows average monthly retail prices in states operated by PJM Interconnection and Mid-Columbia power markets respectively. Retail prices in Washington and Oregon are lower compared to the retail rates in New Jersey, New York and Pensylvania, which are covered by the PJM Interconnection. Moreover, they are below the national average, an indication that the Northwest market is supplied by abundant hydropower capacity compared to other US markets.

In the case of natural gas, it has been argued that the level of inventory, approached by the concept of convenience yield, is a determinant of electricity basis during the peak hours of the day. The same rationale is applied in this chapter to examine the effect of convenience yield of coal futures contracts on the distribution of base load spot and futures electricity prices.
Chapter 6: Empirical analysis—The case of coal in power generation

6.6 Coal convenience yield and electricity basis during the off-peak hours

An important issue on the examination of the proposition is to find an equivalent for the different energy units between coal and electricity. The processing cost of coal, depends on characteristics, such as the moisture content, ash content, BTU content, sulfur content and the efficiency of the generating unit.

According to Cinergy Corporation\(^{53}\), the efficiency of a coal fired power plant is on average at 10,000 Btu per kWh. While in the case of natural gas, the relationship that conveyed fuel and end product (electricity) was straightforward, because natural gas caloric value is measured in Btus, this is not the case for coal. Trading of coal in the US, is specified upon short tons, thus we have to specify the appropriate content of coal in Btus, required (approximately) for the generation of a MWh of electricity. The reason that we refer to the British thermal unit of energy is because of its extensive use by the power generation industries.

| Table 6.2: Conversion measures per physical units in Coal, Electricity and Natural Gas |
|---------------------------------|-------------|-------|-----------------|
| **Coal**                       |             |       |                 |
| 1 Short ton                    | 19988000 Btus | 21279.4 MJ | 0.907 Metric Tones |
| **Electricity**                |             |       |                 |
| 1 kWh                          | 3412 Btus   | 3.6 MJ | -               |
| **Natural Gas**                |             |       |                 |
| 1 Cubic Feet                   | 1028 Btus   | 1.08 MJ | -               |

Source: EIA

According to Table 6.2, which shows energy resources and its equivalent measures, a short ton of coal is proportional to 20 MBtus. Assuming that 10,000 Btus is the average efficiency for the generation of a kWh from coal, it stems that generation of 1 MWh requires 10 MBtus; equivalently ½ short ton of coal. This means that in the suggested proposition, in which MWh relate to thermal units through the heat rate parameter, the latter equals to 0.5 (HR=0.5). In other words, power plants with average efficiency of 10,000 Btus per kWh need, on average, half short ton of coal for the generation of 1 MWh of electricity.

6.7 Estimation Results

In this section the estimates from the regression of convenience yield from Central Appalachia futures contracts, the interest payment on coal’s spot price and the variables of the cooling / heating degree-days on Mid-Columbia power prices are examined. Similarly to the case of natural gas (which was assumed to be the marginal fuel in the merit order dispatch during the peak hours) we use data on coal and base load electricity prices to obtain a quantitative indication of the impact of convenience yield on the basis of Mid-Columbia power prices.

---

\(^{53}\) Cinergy Corporation is a company that produces and distributes electricity for customers located in Indiana, Kentucky, and Ohio. The company operates coal-fired and gas-fired power plants.
Chapter 6: Empirical analysis - The case of coal in power generation

For short trading periods, where the assumption of zero interest rate is made, despite the negative coefficient of the convenience yield of the CAPP coal futures contracts, the p-value shows that the result is not significant even at 90% confidence level. Therefore, it has no impact on the basis of Mid-Columbia electricity prices during the off-peak hours. In contrast, the effect of the weather related energy use variables on the basis is negative with significant t-statistic for temperatures lower than 15° Celsius, hence there is an impact of lower heat in the determination of spot and futures electricity prices.

Table 6.3: Mid-C hub-estimated parameters of the proposed relationship, (Case I)

<table>
<thead>
<tr>
<th>Dependent Variable: Basis</th>
<th>1-pos</th>
</tr>
</thead>
<tbody>
<tr>
<td>Included Observations: 1214</td>
<td></td>
</tr>
<tr>
<td><strong>Explanatory Variables</strong></td>
<td></td>
</tr>
<tr>
<td>Constant</td>
<td>1.531</td>
</tr>
<tr>
<td>(0.0000)</td>
<td></td>
</tr>
<tr>
<td>N_Z_t</td>
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</tr>
<tr>
<td>(0.1789)</td>
<td></td>
</tr>
<tr>
<td>HDD</td>
<td>-0.450</td>
</tr>
<tr>
<td>(0.0018)</td>
<td></td>
</tr>
<tr>
<td>CDD</td>
<td>0.548</td>
</tr>
<tr>
<td>(0.1280)</td>
<td></td>
</tr>
<tr>
<td>Sample period</td>
<td></td>
</tr>
<tr>
<td>(Daily observations Monday-Friday)</td>
<td>Aug. '04-Jun. '09</td>
</tr>
<tr>
<td>Adj-R²</td>
<td>0.06</td>
</tr>
<tr>
<td>Prob. (F-Statistic)</td>
<td>0.0000</td>
</tr>
</tbody>
</table>

(*) The numbers in parentheses are the probability value

The next step is to examine the impact of the convenience yield for higher maturities, in which case the interest foregone parameter or the product of the spot coal price and the nominal interest rate is taken into consideration. In the case of close to maturity futures contracts (monthly futures contracts), the regression estimates are similar to the preceding finding. In contrast, estimated coefficients for higher trading periods are consistent with the presumption that convenience yield, assuming that coal is the marginal fuel, is inversely related to the basis of base-load electricity prices.

At the same time, however, the robustness of the estimates should be considered by the time an I(1) variable has been incorporated in the regression. According to the estimations obtained, the interest foregone parameter is statistically significant for the one and three months holding period. However, stationarity tests of the error term indicate that in most of the cases the disturbances lie inside the unit root cycle. This is an undesirable outcome, because we would expect that by the time the series is non stationary it would affect the “stability” of the estimated regression. In this case, it can be said that the stationarity of the estimated residuals reflect, by all means, the stationarity properties of the dependent variable, hence the outcome for at least these two cases is rather ambiguous.
Table 6.4: Mid-C hub-estimated parameters of the proposed relationship, (Case II)

<table>
<thead>
<tr>
<th>Dependent Variable: Basis</th>
<th>1-pos</th>
<th>3-pos</th>
<th>6-pos</th>
<th>12-pos</th>
</tr>
</thead>
<tbody>
<tr>
<td>Included Observations: 1214</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Explanatory Variables</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Constant</td>
<td>1.904</td>
<td>3.105</td>
<td>3.268</td>
<td>1.745</td>
</tr>
<tr>
<td></td>
<td>(0.0000)</td>
<td>(0.0000)</td>
<td>(0.0000)</td>
<td>(0.0000)</td>
</tr>
<tr>
<td>$S_{t}^{Marginal Fuel}$</td>
<td>-2.65</td>
<td>-2.788</td>
<td>1.169</td>
<td>0.499</td>
</tr>
<tr>
<td></td>
<td>(0.0000)</td>
<td>(0.0185)</td>
<td>(0.4666)</td>
<td>(0.1391)</td>
</tr>
<tr>
<td>$NZ_{t}^{Marginal Fuel}$</td>
<td>0.296</td>
<td>-0.502</td>
<td>-0.633</td>
<td>-0.832</td>
</tr>
<tr>
<td>(Appalachia Coal)</td>
<td>(0.0891)</td>
<td>(0.0140)</td>
<td>(0.0005)</td>
<td>(0.0004)</td>
</tr>
<tr>
<td>HDD</td>
<td>-0.481</td>
<td>-1.426</td>
<td>-2.113</td>
<td>-0.493</td>
</tr>
<tr>
<td></td>
<td>(0.0008)</td>
<td>(0.0000)</td>
<td>(0.0000)</td>
<td>(0.0006)</td>
</tr>
<tr>
<td>CDD</td>
<td>0.600</td>
<td>-0.029</td>
<td>-0.456</td>
<td>-0.755</td>
</tr>
<tr>
<td></td>
<td>(0.0086)</td>
<td>(0.9425)</td>
<td>(0.2200)</td>
<td>(0.0001)</td>
</tr>
<tr>
<td><strong>Sample period</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Adj-R²</td>
<td>0.08</td>
<td>0.30</td>
<td>0.43</td>
<td>0.51</td>
</tr>
<tr>
<td>Prob. (F-Statistic)</td>
<td>0.0000</td>
<td>0.0000</td>
<td>0.0000</td>
<td>0.0000</td>
</tr>
</tbody>
</table>

*The numbers in parentheses refer to the probability values

The preceding rationale is not observed for higher contract maturities, in which case the interest foregone parameter has an insignificant t-statistic, whereas the coefficient of the convenience yield indicates that its variation is a fraction of the variation in the basis for Mid-Columbia electricity prices. In addition, the coefficient of determination ($R^2$) implies a good explanatory power since it explains more that 40% of the 6 and 12-months basis for Mid-Columbia off-peak prices.

The better fit of the data for deferred contract maturities in the previous results can be related to the observation that coal sales are based, at least to a large extent, on long term contracts affecting in this way the commodity’s future price. As it was mentioned earlier, shipments of coal purchased for delivery within a specified time period (usually a year) is a common practice in the coal market. In this way producers and power generators as well can use those types of transactions to hedge against uncertainties with respect to the level of prices and at the same time to secure a certain proportion of energy requirements.

In addition to the preceding findings it can be examined whether the interest foregone can be excluded from the regression without committing an omitted bias misinterpretation. By regressing $S_{t}^{Marginal Fuel}$ on each of the variables of the regression it is observed that the coefficient is close to zero for all holdings periods except of the nearby trading period. According to those findings, it can be argued that the variable can be deducted from the regression with estimated regression parameters appearing in Table 6.6.
Table 6.5: Mid-Columbia hub, unit root tests of the residuals from the Case II regression

<table>
<thead>
<tr>
<th></th>
<th>1-pos</th>
<th>3-pos</th>
<th>6-pos</th>
<th>12-pos</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>ADF</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>1. No constant term and no linear trend</td>
<td>I(0)</td>
<td>I(0)</td>
<td>I(0)</td>
<td>I(0)</td>
</tr>
<tr>
<td>2. Constant term but not a linear trend</td>
<td>I(0)</td>
<td>I(0)</td>
<td>I(0)</td>
<td>I(0)</td>
</tr>
<tr>
<td>3. Constant term and a deterministic linear trend</td>
<td>I(0)</td>
<td>I(0)</td>
<td>I(0)</td>
<td>I(0)</td>
</tr>
<tr>
<td><strong>Philips-Peron</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>1. No constant term and no linear trend</td>
<td>I(0)</td>
<td>I(0)</td>
<td>I(0)</td>
<td>I(0)</td>
</tr>
<tr>
<td>2. Constant term but not a linear trend</td>
<td>I(0)</td>
<td>I(0)</td>
<td>I(0)</td>
<td>I(0)</td>
</tr>
<tr>
<td>3. Constant term and a deterministic linear trend</td>
<td>I(0)</td>
<td>I(0)</td>
<td>I(0)</td>
<td>I(0)</td>
</tr>
<tr>
<td><strong>KPSS</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>1. Intercept</td>
<td>I(1)</td>
<td>I(1)</td>
<td>I(0)</td>
<td>I(0)</td>
</tr>
<tr>
<td>2. Trend and intercept</td>
<td>I(0)</td>
<td>I(0)</td>
<td>I(0)</td>
<td>I(0)*</td>
</tr>
</tbody>
</table>

Notes: *The null (the series is stationary) is accepted at α=1%. See the appendix of the chapter for the test statistics of the ADF, PP and KPSS tests.

The estimated coefficients from a regression between variables of the same order of integration indicate that a negative relationship exists between the convenience yield and the price difference between futures and concurrent spot prices at the Mid-Columbia trading hub. Therefore, the data supports the negative relationship expected between fuel reserves and the basis of power prices.

Table 6.6: Mid-Columbia, estimated parameters of the proposed relationship, (Case III)

<table>
<thead>
<tr>
<th>Dependent Variable: Basis</th>
<th>3-pos</th>
<th>6-pos</th>
<th>12-pos</th>
</tr>
</thead>
<tbody>
<tr>
<td>Included Observations: 1214</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Explanatory Variables</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Constant</td>
<td>2.697</td>
<td>3.483</td>
<td>1.832</td>
</tr>
<tr>
<td>(0.0000)</td>
<td>(0.0000)</td>
<td>(0.0000)</td>
<td>(0.0000)</td>
</tr>
<tr>
<td>NZ_{Appalachia Coal}</td>
<td>-0.534</td>
<td>-0.606</td>
<td>-0.819</td>
</tr>
<tr>
<td>(0.0010)</td>
<td>(0.0000)</td>
<td>(0.0000)</td>
<td>(0.0003)</td>
</tr>
<tr>
<td>HDD</td>
<td>-1.386</td>
<td>-2.137</td>
<td>-0.496</td>
</tr>
<tr>
<td>(0.0000)</td>
<td>(0.0000)</td>
<td>(0.0005)</td>
<td>(0.0005)</td>
</tr>
<tr>
<td>CDD</td>
<td>-0.079</td>
<td>-0.436</td>
<td>-0.752</td>
</tr>
<tr>
<td>(0.7456)</td>
<td>(0.1121)</td>
<td>(0.0001)</td>
<td>(0.0001)</td>
</tr>
<tr>
<td><strong>Sample period</strong></td>
<td>Aug. '04-Jun. '09</td>
<td>Aug. '04-Jun. '09</td>
<td>Aug. '04-Jun. '09</td>
</tr>
<tr>
<td><strong>Adj-R^2</strong></td>
<td>0.31</td>
<td>0.42</td>
<td>0.51</td>
</tr>
<tr>
<td><strong>Prob. (F-Statistic)</strong></td>
<td>0.0000</td>
<td>0.0000</td>
<td>0.0000</td>
</tr>
</tbody>
</table>

Moreover, the demand for electricity described by the heating and cooling degrees parameters indicate that a stronger effect in the variation of the basis is caused when lower temperatures are observed in the region served by the Mid-Columbia hub. By summarizing, it
can be argued that according to the historical data employed, the level of coal reserves is inversely related to the convenience yield, as predicted by the storage theory. Moreover, some of the regression estimates indicate that in cases of higher supplies in coal inventory the futures price for electricity during the off-peak hours is expected to vary at a higher level relatively to the concurrent spot price (positive basis). This should be attributed to the modest rise of coal prices as a result of lower consumption mainly from the power industry (given that inventory accumulation is observed also when consumption has been reduced).

On the other hand, the coefficients of heating and cooling degree-days are significant in the cases examined. An interpretation on this finding can be that high or low temperatures contribute to increased use of the fuel (this trend is depicted also in the seasonal pattern of inventory level) for electricity generation. As coal consumption increases pressures are expected to be recorded on the cash price. Since coal is the largest power generating fuel in USA it is expected that generation costs will be affected by the increased fuel prices. Accordingly the price of electricity will change as well, sometimes to a level higher than the futures price leading to a negative basis.

6.8 Accounting for both fuels

Until this point it is evident that the assumption of a competitive marginal-cost based dispatch is undertaken so as to address that power units are chosen by the system operator to run primarily on their operating costs, of which fuel costs account for the largest share. However, by the time the spot electricity prices employed in the empirical part of the study refer to daily averages, whereas in the real-time the market clearing price is determined on an hourly basis\(^\text{54}\), it is possible that a mixture of two fuels can be marginal at the same time.

Even though, the choice of the US electricity markets under examination relies on the information (provided by the FERC) about the type of the marginal fuels used in each region, in this section we examine whether the inclusion of an additional fuel improves the explanatory power of the proposition. For that purpose, in the case of peak electricity prices the convenience yield of both Henry Hub natural gas and Appalachia coal futures are taken into consideration.

The following remarks, however, should be underlined. Firstly, the choice of peak-prices relates to the allocation of energy resources when demand for power is higher. In that case the demand curve for power is intersected with the (near) vertical segment of the supply curve, where power plants with different generating fuels are found as they vary their output to adapt to the changes of electricity demand. Therefore, a combination of fuels is more likely to be observed during the peak load rather than in the off-peak, where demand is usually

\(^{54}\) Data provided by Datastream with respect to electricity prices refer to daily averages. Power prices for each of the 24 hours of the day as they are settled by the system operator were not available in the case of US power markets.
met by extensive use of certain types of energy resources (for instance coal in USA or hydro in Canada). In terms of our analysis, coal and natural gas power units may be used interchangeably during certain hours of higher demand.

Secondly, the interest foregone parameter for both commodities is excluded from the regression. According to the results of the empirical tests in the previous sections the estimated coefficient has no statistical meaning, implying that there is no explanatory value on the variation of basis in electricity prices. Moreover, by removing the specific component from the regression we do not miss explanatory power in the attempt to examine the impact of the fuel’s convenience yield on electricity basis. It is implied therefore, that the carrying charges within a certain time period, such as the foregone interest, may have lower impact in the operation of the power industry, considering also the nature of the commodity and the requirements of power plants for readily fuel supplies in order to adjust production to the changes of demand.

Based on the preceding arguments, the basis from PJM and Palo Verde spot and futures peak prices is regressed on the net of storage convenience yield estimated from natural gas and coal prices and the variables of heating / cooling degree-days as well.

**Figure 6.6: New generation in the area controlled by PJM Interconnection 2000-2006**

![Graph showing new generation in the area controlled by PJM Interconnection 2000-2006]

**Source:** Synapse Energy Economics

In the case of the PJM Interconnection, the results indicate that the convenience yield on Appalachia coal futures offers no explanatory value on the variation of the basis for a probability value higher than 5%, whereas the negative relationship emerging from the proposition is not supported by the data. In contrast, the net of storage convenience yield on Henry Hub futures contracts is consistent with the proposition. According to the results, it is presumed that in this power market additional supply of electricity is mainly covered with gas
usage. This presumption can be also supported by the displacement of coal fired plants by gas utilities, which is observed in the area controlled by PJM Interconnection. According to a study [67], in the PJM region a completion of at least 16,000 MW has taken place between 2000-2006, most of which comes from gas-fired plants (combined cycle or combustion turbine).

Table 6.7: PJM Interconnection-estimated parameters using as regressors the convenience yield on Henry hub and Appalachia futures contracts

<table>
<thead>
<tr>
<th>Dependent Variable: Basis</th>
<th>1-pos</th>
<th>3-pos</th>
<th>6-pos</th>
<th>12-pos</th>
</tr>
</thead>
<tbody>
<tr>
<td>Included Observations: 1.530</td>
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<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Explanatory Variables</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Constant</td>
<td>1.967</td>
<td>3.657</td>
<td>2.336</td>
<td>1.223</td>
</tr>
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<td>(0.0000)</td>
<td>(0.0000)</td>
<td>(0.0000)</td>
<td>(0.0000)</td>
<td></td>
</tr>
<tr>
<td>N2\textsuperscript{Marginal Fuel} (Henry Hub Natural Gas)</td>
<td>-4.135</td>
<td>-2.554</td>
<td>-5.444</td>
<td>-7.127</td>
</tr>
<tr>
<td>(0.0000)</td>
<td>(0.0126)</td>
<td>(0.0000)</td>
<td>(0.0000)</td>
<td></td>
</tr>
<tr>
<td>N2\textsuperscript{Marginal Fuel} (Appalachia Coal)</td>
<td>0.443</td>
<td>-0.222</td>
<td>0.216</td>
<td>0.150</td>
</tr>
<tr>
<td>(0.0633)</td>
<td>(0.0867)</td>
<td>(0.0575)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>HDD</td>
<td>-1.522</td>
<td>-2.756</td>
<td>-1.175</td>
<td>-1.661</td>
</tr>
<tr>
<td>(0.0000)</td>
<td>(0.0000)</td>
<td>(0.0000)</td>
<td>(0.0000)</td>
<td></td>
</tr>
<tr>
<td>CDD</td>
<td>-2.355</td>
<td>-5.707</td>
<td>-4.576</td>
<td>-2.837</td>
</tr>
<tr>
<td>(0.0000)</td>
<td>(0.0000)</td>
<td>(0.0000)</td>
<td>(0.0000)</td>
<td></td>
</tr>
<tr>
<td>Sample period</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>(Daily observations Monday-Friday)</td>
<td>Aug. '04-Jun '09</td>
<td>Aug. '04-Jun '09</td>
<td>Aug. '04-Jun '09</td>
<td>Aug. '04-Jun '09</td>
</tr>
<tr>
<td>Adj-R\textsuperscript{2}</td>
<td>0.16</td>
<td>0.38</td>
<td>0.36</td>
<td>0.44</td>
</tr>
<tr>
<td>Prob(F-statistic)</td>
<td>0.0000</td>
<td>0.0000</td>
<td>0.0000</td>
<td>0.0000</td>
</tr>
</tbody>
</table>

* The numbers in parentheses refer to the probability values

In contrast, the results in the Palo Verde case are different compared to the PJM market since the estimates of the convenience yields on both commodities offer an economic meaning to the variation of the basis of electricity prices. The t-statistics are significant, indicating also a higher share in the basis’ variation from the supply side of natural gas. According to that results, it can be assumed that in the power market covered by the Palo Verde hub, coal power units operate supplementary to natural gas plants when demand for electricity increases and in this way they might as well determine the market clearing price during certain hours within the peak time segmentation.

A possible explanation on that observation can be associated with the capacity margin, i.e., the amount of power required as reserve during the hours of higher load. By the time electricity supplied from the grid is consumed the moment is produced the power industry uses additional supplies (or in other words maintains capacity margins higher than a specified level of the usual amount of power produced) in order to meet higher demand.
Due to limitations that may arise in the supply from gas fired plants in the Palo Verde market (for instance the maximum amount which is possible to be supplied by those units) the required capacity margin can be effectively supplied by coal power units. In this way, the bids from those units submitted in the power pool are also taken in consideration at the dispatch.
### Appendix

#### Table 6.9: Unit root tests for the PJM, Palo Verde and Henry Hub spot prices

<table>
<thead>
<tr>
<th>Case</th>
<th>1-pos</th>
<th>3-pos</th>
<th>6-pos</th>
<th>12-pos</th>
</tr>
</thead>
<tbody>
<tr>
<td>Case 1. No constant term and no linear trend</td>
<td>-7.329 (0.000)*</td>
<td>-6.305 (0.000)</td>
<td>-5.977 (0.000)</td>
<td>-12.640 (0.000)</td>
</tr>
<tr>
<td>Case 2. Constant term but not a linear trend</td>
<td>-7.326 (0.000)</td>
<td>-6.303 (0.000)</td>
<td>-5.974 (0.000)</td>
<td>-12.634 (0.000)</td>
</tr>
<tr>
<td>Case 3. Constant term and a deterministic linear trend</td>
<td>-7.658 (0.000)</td>
<td>-6.357 (0.000)</td>
<td>-6.008 (0.000)</td>
<td>-12.645 (0.000)</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Case</th>
<th>1-pos</th>
<th>3-pos</th>
<th>6-pos</th>
<th>12-pos</th>
</tr>
</thead>
<tbody>
<tr>
<td>Case 1. No constant term and no linear trend</td>
<td>-8.032 (0.015)</td>
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<td>-8.223 (0.000)</td>
<td>-37.995 (0.000)</td>
</tr>
<tr>
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<td>Case 2. Trend and intercept</td>
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<td>0.036 (0.22; 0.15; 0.12)</td>
<td>0.157 (0.22; 0.15; 0.12)</td>
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**Notes:** In the ADF and the Phillips-Perron tests, the reported values in the table are the estimated t-statistics and the p-values in the parentheses for the unit root test, according to the three specific situations. The calculated statistics are those reported for the Dickey-Fuller and the Philips-Perron tests. The critical values (for both tests) at 1%, 5% and 10% levels of significance are: **for Case 1:** –2.57, -1.94 and -1.62; **for Case 2:** –3.43, -2.86 and –2.57; and for **Case 3:** –3.96, –3.41 and –3.13 respectively.

The KPSS test is based on a Lagrange Multiplier autocorrelation procedure and tests the null hypothesis that the series is stationary against the alternative hypothesis of non-stationarity. The null hypothesis is accepted if the test statistic is lower than the critical value. In the parentheses appear the asymptotic critical values for 1%, 5% and 10% level of significance.
Chapter 7: Summary and conclusions

The last decade an increasing number of countries have liberalized their power sector. In contrast to the regulated environment where prices reflected the costs of generation, transmission and distribution of electricity, prices in deregulated markets are determined by the equilibrium of demand and supply. Among the main effects of deregulation is the emergence of price volatility and sudden upward movements. Those features have led to the introduction of risk management tools as a means of mitigating unanticipated price changes. For that purpose, electricity contracts for future delivery have been introduced, which are traded either over the counter through bilateral agreements (forward contracts) or through organized power exchange markets (futures contracts).

The literature on the valuation of futures electricity contracts postulates that the cost-of-carry or storage theory cannot be applied in the power sector. The storage theory is an arbitrage based relationship, which relies on the presumption that inter-temporal price differences reflect the cost of carrying a commodity until the date of the contract’s maturity. The trader borrows money to buy the commodity that carries until the expiration of the futures contract. Upon delivery the revenues from the futures contract are used to repay the loan, whereas any gain from the transaction is considered an arbitrage profit. By the time electricity has limited storage capabilities it cannot be considered as a tradable asset in the context of buying and resale it at a future date. Due to that reason, the existing studies with respect to power futures contracts employ the assumptions of normal backwardation theory to specify the existence of a risk premium in the futures market and its main determinants.

Although electricity cannot be economically stored in significant quantities, it is argued that an indirect type of storage exists through the fuel(s) used in power generation. A typical example in favour of that presumption is generation from hydropower plants. These units can operate flexibly and with a rapid response to demand changes by using water inflows accumulated in reservoirs. In the literature, the role of indirect storage in the power sector has been underlined by Routledge et al. (2001) who study the effect of physical storage and conversion options on commodities’ price distribution.

We argue that the assumption of indirect storage can also incorporate the case of fossil fuels, particularly natural gas and coal because their demand is significantly driven by the power sector. Coal-fired units provide significant amount of power in many regions around the world, whereas natural gas has become very popular in the electricity industry due to its lower carbon footprint and the rapid response of gas-fired units in load-following and balancing capabilities. Moreover, demand for natural gas is expected to rise in the next decades as energy efficient targets for reduction of greenhouse gas emissions have been set.

In this study, the potential of an indirect type of storage in the power sector is associated with the conversion of commodity inputs (fuels) in finished products (electricity) by taking
into consideration the demand and supply across the industry. The latter implies that the price of electricity is a function of the fuel cost. It is expected therefore, that besides the dynamics that take place in the electricity industry per se, demand and supply changes in major fuel markets should have an impact on the distribution of power prices.

It is worth noting that the supply capacity of natural gas available to respond to the changes in demand varies due to weather conditions and the use of the commodity for residential needs. Consequently, adjustments in gas prices as a result of deviations in the supply side affect the magnitude of changes in electricity prices, at least in the short term. Respectively, in the Scandinavian countries where hydropower generation covers substantial part of demand for electricity, higher prices during winter are accompanied by diminishing water reserves in dams. The preceding examples indicate the role of fuels’ capacity in the pricing of electricity. According to that perspective and given the assumption that fuel cost is the main determinant of power prices it is proposed that the theory of storage can be incorporated in the valuation of futures electricity contracts.

In this context, the difference between the futures and the contemporaneous spot electricity prices has been employed. The basis, which shows the discrepancy between futures and contemporary spot prices offers an indication of how efficient a hedging exposure is by employing also the conditions (demand, supply, technology, inventory) prevailing at the commodity’s market. On the other hand, the risk premium, which is defined as the difference between futures and expected spot prices depends on the positions taken in the futures market (the hedging pressure) and incorporates supply and demand conditions anticipated to prevail at the date of the contract’s maturity.

The proposed relationship is based on certain assumptions related to the operation of the power industry. Firstly, the wholesale market of the power sector is taken into consideration because at the specific segment of the supply chain variation in prices reflects the cost of power generation. In contrast, retail power prices that represent the tariff charged to end consumers (e.g. households, enterprises) exhibit small variation as they have remained, at least partially, regulated. That characteristic renders retail prices inappropriate to capture variations recorded in fuel’s demand and supply.

Moreover, a competitive power market is encountered in which prices reflect the marginal cost of production. Price offers made by power generators are classified in a dispatch scheme known as the merit order that ranks the bids in an ascending order. The market participants with lower offers are called by the system operator to supply the grid and receive a uniform price, known as the market clearing price, which is determined by the generator with the highest offer in the rank. According to that perception, this pricing method refrains power generators from offering bids different than their marginal cost of production. Otherwise, they run the risk of being excluded from supplying the market if lower price bids prevail.
The assumption of a uniform price paid to power generators enables to focus on particular type of fuels and their implications on the pricing of electricity instead of the total mix of energy resources used in electricity generation. Assuming that the energy resource or the marginal fuel as we have denoted in the analysis, is storable and the existence of a conversion yield related to the transformation of a certain type of energy into electricity, a relationship between the basis of electricity prices and the carrying costs of the marginal fuel is proposed, based on the argument that the fuel cost comprises the main determinant of the spot electricity price.

The proposition is an equilibrium relationship based on arbitrage assumptions between two time periods. The main implication is the negative relationship that conveys the basis of electricity and the convenience yield of the marginal fuel. The latter suggests that small supply capabilities to meet demand fluctuations in the fuel market should be associated with increased volatility in the cash market and significant upward price movements as well. Moreover, underutilized supply should be reflected through higher estimates of convenience yield. Therefore, according to the proposed relationship, in such occasions it should be expected that futures electricity prices will be lower than the contemporaneous spot price. Likewise, during periods of increased storage supplies the convenience yield should fall and the basis of electricity will be positive. This implies that in the existence of adequate supplies an increase in the price of the fuel is less likely to occur. Respectively, generation costs of electricity shall be moderate and consequently a surge in the wholesale power price is less likely to occur.

The proposed relationship is empirically examined with data from US energy markets by taking also into consideration the differences recorded in the rates between peak and off-peak hours of demand for electricity. According to FERC, in power markets such as the PJM Interconnection and the Palo Verde, demand for electricity during the peak hours of the day is almost entirely provided by gas-fired power plants. Respectively, the Mid-Columbia trading hub is a power market in which coal-fired units cover a significant proportion of electricity demand in the region. In order to incorporate in the empirical study the proposed implications of natural gas and coal, we have employed price data from the Henry Hub and the Central Appalachia markets respectively. The significant trade volume of the commodities at those markets renders their prices as benchmarks of the market prices prevailing at different regions.

As far as electricity prices are concerned, basic statistical measures indicate that PJM and Palo Verde prices exhibit significant volatility, skewness, kurtosis and autocorrelation, properties which have been also recorded in the literature for other power markets. In contrast, the same measures for the prices of Henry hub natural gas exhibit a smaller magnitude, whereas smaller variation is recorded in Central Appalachia coal prices. That feature relates to the storable nature of the fossil fuels, which implies that inventory capabilities have an effect on
smoothing price deviations. Finally, spot electricity prices exhibit higher estimates of standard deviation compared to futures prices, implying that they are influenced in a more direct way by short-run market dynamics such as demand for power, weather conditions and power plant availability.

In addition, given that natural gas and coal are storable commodities we have examined the implications of the cost-of-carry theory according to the interest-adjusted basis and a direct test between the convenience yield and the level of reserves. For the interest-adjusted basis proposed by Fama and French (1988) futures and spot prices for both fuels are employed and we find that the (interest adjusted) basis shows higher volatility in negative estimates. This implies that demand or supply shocks cause higher variation in the spot prices compared to the futures prices when inventories are low. According to the second approach the regression of the convenience yield on the level of inventory (on a monthly basis) confirms the inverse relationship proposed by the cost-of-carry theory.

The proposition is tested using the OLS method with the regression estimates indicating that (in the majority of the cases employed) the negative relationship between the basis of electricity and the convenience yield of natural gas futures contracts can be accepted both for the PJM and the Palo Verde markets, since the parameter estimates are negative and statistically significant for the holding periods examined. Therefore, the convenience yield which is used as a proxy of the level of fuel reserves has an impact on the variation of spot and contemporaneous electricity prices during the hours of higher demand for electricity.

On the other hand, by assuming that coal is the principal fuel used in the generation process, we find that spot electricity prices during the off-peak hours have lower mean values compared to the prices during the peak hours of the day, whereas the magnitude of price jumps is lower. Hence, the use of various energy resources in power production as demand for electricity varies during the day reflects the differences in generation costs, which in their turn are depicted in electricity peak and off-peak rates.

By examining the proposed relationship between the basis of base load electricity prices and the convenience yield of coal futures contracts, we obtain statistically significant parameters for the cases of three, six and twelve months to maturity. Therefore, as in the case of natural gas the inventory level of the marginal fuel affects the cash price and subsequently the price distribution of electricity. The interpretation of that finding is that high reserves in the coal market should be associated with a positive basis of electricity prices, whereas in times of underutilized coal supply, spot electricity prices might be above futures prices, leading in this way to a negative basis.

Another finding of the empirical work is the better fit of the data with respect to futures contracts of higher maturity. This result should be related to the nature of electricity where for short trading periods the prices are mainly determined by weather conditions and
unexpected changes either in the demand or the supply side. Instead, the effect of fuel cost in the power generation process is usually reflected in the trading of futures contracts for higher maturities.

The preceding results are based on the presumption that power generating units are paid the same price by the system operator which is determined by the unit with the highest each time accepted offer (the marginal fuel). However, it can be argued that in some power markets there are units fuelled by different energy resources that operate interchangeably and for that reason the price of electricity might reflect an average generation cost.

In order to examine this argument we have incorporated in the empirical analysis the regression of the convenience yields for both natural gas and coal futures contracts on the basis of electricity prices during the peak hours of the day. The use of peak prices indicate that as load increases the demand curve intersects with the convex part of the electricity supply curve, in which a higher proportion of different types of power units coexist. According to the results, for the PJM peak prices the coefficients of the convenience yield for Appalachia futures contracts are statistically insignificant. This finding may be associated with the extensive use of power production from gas units during the hours of higher demand that subsequently gives a clear indication of those units “stacked” in the upper part of the supply curve. This is also supported by the view that in the area covered by the PJM Interconnection coal power plants are displaced by gas units, which implies the increasing share of natural gas in the energy mix.

In contrast, in the case of Palo Verde peak prices the regression estimates of the convenience yield for both fuels are statistically significant which implies that variation of the level of inventory in those fossil fuels has an impact on the basis of electricity. This finding should be associated with the requirement of additional supplies in order the capacity margin in the market to be sustained. Given that electricity is not storable and the need of demand and supply to be constantly balanced this margin can be supplied by coal power units. In this occasion the offers submitted by those units are also taken into consideration at the dispatch.

In conclusion, electricity exhibits major differences with respect to other energy commodities due to the inability of effective storage. Based on the presumption that an indirect proportion exists between electricity and the fuel used in power generation, a relationship conveying the basis of electricity prices and the convenience yield of the fuel has been proposed, which is also empirically tested with data from the US energy market. It should be mentioned that the proposition does not intend to model the distribution of electricity prices. Instead, it examines the characteristics related to the supply side of the fuel market which is involved in the power industry in order to incorporate the implications of the storage theory. The empirical study shows that the independent variables proposed have an impact on the variation of the basis;
therefore, the proposition offers some valuable information on the determinants of electricity prices.
Bibliography


[74] 2010 State of the market report for PJM, Section 4, Interchange Transactions
Appendix B

In the following section we examine the relationship between convenience yield and its characteristics with respect to commodities that their demand is either stemming from a single resource or from various economic activities.
1. Introduction

End use demand, which is driven by different economic sectors is usually subject to fluctuations. Therefore, an increase in demand by one sector reduces the available for consumption commodity for the other sectors, unless an increase in supply takes place either by expanding the level of production or making use of accumulated inventories. Given that in the short run an adjustment by the supply side is usually limited, the use of inventory is essential in smoothing consumption.

This section examines whether convenience yield shows different characteristics in commodity markets where demand expands to multiple uses compared to those markets in which consumption is driven from a single use. In the former case, changes in demand should have an impact on the spot price, particularly in the absence of substitutes, and subsequently in the value of the convenience yield, since it is defined as the spread between spot and futures prices.

Provided that commodity prices are a function of market supply and demand the effect of inventories and the duration of the change in demand (or the disruption in supply) should be also encountered. In the first case, inventory holdings are expected to smooth excess demand over supply and due to that reason stocks are considered as a source of flexibility in case of shifts in demand (or disruptions in supply). By assuming a commodity market where the consumption is driven by more than one economic sectors, we examine the effect of a change in demand on the level of the convenience yield presuming also that the commodity is storable and that short-term adjustments in the supply side are limited\(^5\) (therefore supply is more elastic in the long run than in the short run).

For that purpose Figure 1 illustrates the case of a short-term increase in demand. The distinction with respect to the duration (temporary or persisting) of the demand shift should be made because it is expected to have different impact on prices. Diagram 1a, depicts the relationship between stocks and demand for storage. The level of inventory in the market is considered to be fixed at a specified period, while the demand for storage (\(N_i\) curve) is downward sloping, indicating the negative relationship between inventories and spot prices (lower prices in case of sufficient supplies and vice versa). The demand and supply curves in Figure 1B are represented by D and S respectively, whereas production is denoted by Q. Finally, Figure 1C illustrates the negative relationship conveying demand for storage and convenience yield, implying that the flow of benefits is small when inventories are large, while it can rise substantially when stocks become smaller.

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\(^5\) This is actually the case in energy commodities where new supplies require considerable time for implementation.
A potential change in demand leads the respective curve to the right and excess demand—represented by the solid line on Figure 1B, is met by reduction of stocks since by assumption the production in the short-run cannot respond to the demand change. The stock supply curve therefore, will move to the left and the equilibrium point in the economy will change from point A to point B. The price increase, however, will not persist as the shock in demand is temporary. While excess demand is falling, the spot price is gradually decreasing as re-accumulation of inventories takes place (under the condition that production exceeds consumption). When there is no further inventory accumulation the stock supply curve will have returned to its original level and the economy’s equilibrium point will be at point A. Therefore, inventories have a productive value (production is augmented by the withdrawal from inventory) reducing in that way the size of upward price movements.
The dynamics between demand and convenience yield

The intuition behind this demand change is that convenience yield is expected to increase as the economy approaches the new equilibrium point (point B), which is located to the left of the demand for storage curve (Figure 1C). Similarly to the spot price, however, convenience yield will reduce as demand falls and equilibrium is restored. Those upward (or downward) changes in the convenience yield are indicative of a mean reverting behaviour -sudden deviations from a long-run mean level, documented in the literature – for instance in Gibson and Schwartz, 1990.

As mentioned earlier, the preceding characteristics should be associated with a temporary shift in demand. In case the change in demand persists it is expected that higher market prices will probably lead to an increase of the futures price as well, by the time that trading in the futures market incorporates supply and demand conditions expected in the future.

On the other hand, the effect of price volatility on convenience yield should be also taken into consideration. Pindyck (2001) suggests that price volatility associates with higher variation in production and consumption. This in turn should have an increasing effect in the demand for storage, since at any given price of storage (i.e., the convenience yield) market participants will have the incentive to hold more inventories in order to counterbalance potential fluctuations either in production or consumption. The result will be an upward movement in the demand for storage curve and subsequently in the convenience yield (Figure 2).

**Figure 2: The impact of price volatility on demand for storage**

![Figure 2](image)

**Source:** Pindyck

The preceding arguments imply that the structure of convenience yield should be associated with the level of spot price, especially when demand elasticity the responsiveness of demand to changes in prices, over the short run is small. Assuming that periods of low inventory
The dynamics between demand and convenience yield coincide with higher spot prices, a positive correlation between convenience yields and spot prices should be recorded.

2. The case of natural gas and coal

Based on the discussion regarding the effect of demand and supply on spot prices the characteristics of natural gas and coal markets in USA are examined given that demand for each energy commodity has distinctive differences.

Figure 3: Uses of natural gas and coal in USA, 2011

Natural gas has become an essential part in the production process of various end users. In 2011 for instance, almost a third of gas consumption was for electric power generation, while industrial, residential, and commercial sectors accounted for 28%, 19% and 13% of demand respectively (Figure 4A). Instead, coal consumption in the US is almost entirely driven by electric power industries, accounting for more than 93 percent of total demand (Figure 3B).

The diverse use of natural gas is reflected in the price level, which shows significant variation compared to those of coal. Over the period 2004-2011 annual natural gas prices have, on average, fluctuated between a low of $4.0 per MMBtu in 2011 and a high of $9.0 per MMBtu in 2005. At the same period, variation in coal prices is lower ranging from $1.9 per MMBtu in 2007 to $3.7 per MMBtu in 2008[28].
The dynamics between demand and convenience yield

Higher price volatility\textsuperscript{56} in the natural gas markets compared to coal market and the different patterns on a monthly basis indicate that upward pressures on gas prices are more common. In fact, volatility does not describe the level of prices but the degree of variation in prices. Figure 4 shows that in the natural gas market volatility is higher between November and February when residential and commercial end users consume gas for heating, placing in that way upward pressure on prices. Moreover, in case of severe weather conditions the effect on prices can be more intense because supply cannot adjust immediately to the short-term increase of demand. In contrast, volatility in coal prices is lower and with small changes indicating that deviations in prices are not common.

![Figure 4: Average monthly price volatility in natural gas and coal markets, 2008-2011](image)

3. The relationship between price volatility, demand and supply conditions

Fluctuations in prices can be explained through demand and supply. In the gas market, factors on the supply side that affect prices include the production from gas wells, net imports\textsuperscript{57} and net storage withdrawals, which represent the amount of storage withdrawn over gas injections. In the short-term, consumers are limited in their ability to switch fuel

\textsuperscript{56} Price volatility is estimated according to the returns method as the standard deviation of daily relative changes in price. The daily relative price change is computed using a natural lag transformation. Volatility itself is then calculated by multiplying the standard deviation of the daily logarithmic price change for all trading days within a certain time period by the square root of the number of trading days. For the monthly volatility calculation the 21 trading days convention is used:

\[
\text{Volatility}_t = \sqrt{\frac{N}{N-1} \sum_{i=1}^{N} (\Delta p_i - \bar{p}_t)^2} \times \sqrt{N_t}
\]

\(\Delta p_t\) is the log change in daily spot price \(\ln(p_t/p_{t-1})\) and \(N\) the number of trading days.

\textsuperscript{57} Imports less exports.
The dynamics between demand and convenience yield whereas production infrastructure operates near capacity. Those features indicate that natural gas prices are sensitive to market factors that cause either demand or supply disruptions (for instance a change in weather).

**Figure 5: Demand and supply factors that determine the spot price in US natural gas market**

Given that supply and demand are almost never in balance, storage infrastructures are important for the supply side to adjust to seasonal gas demand. The latter is depicted in Figure 6B, which shows that supplies in inventory decrease during the heating season (December through March), when residential and commercial demand increase. Respectively, lower price volatility during the spring, as it is indicated in Figure 5, can be related to the reduction in residential consumption and the accumulation of storage supplies —the refill season from April until October, where excess dry gas production over demand is accumulated in storage facilities.

**Figure 6: Natural gas characteristics in USA, 2011**

(* Net Withdrawals represent the difference between storage withdrawals and injections. Positive values reflect withdrawals of gas from storage, while negative values show injection or accumulation of natural gas in storage. **Source**: EIA)
In this context, it can be argued that in the absence of inventory the magnitude of upward price movements would be higher in case a change in demand or an interruption in supply takes place.

In contrast, changes in consumption patterns in the coal market relate mainly to the level of electricity demand. Coal is most commonly used by base-load power plants that produce electricity with a constant output over the day. In addition, fuel switching from other type of units (for instance natural gas or oil) cannot be implemented, at least in the short term due to constraints on the electric transmission system and the differing technology in the generation processes from other energy resources.

**Figure 7: Coal characteristics in USA, 2010**

In addition, even though weather provides a seasonal pattern for coal consumption it should be underlined that imbalances between supply and demand do not fundamentally affect market activity due to the regional characteristics the market exhibits, such as sufficient stock level and large recoverable reserves that result to small import dependency (Figure 7).

### 4. Convenience yield in categories per year

According to the theory of storage, the difference between the spot and the futures prices gives a measure of the convenience yield. In this section we make a simple empirical analysis on that measure based on natural gas and coal prices data from Henry (gas) Hub and Central Appalachia coal region (CAPP). With this approach we aim to examine whether the estimates of the convenience yield exhibit different characteristics in the particular energy market.

However, by the time convenience yield and storage costs are not easily observable, the estimated values in this section represent the so called net of storage convenience yield, i.e., the difference between the spot price and the discounted futures price:

\[
\text{Net (of storage) Convenience yield}_t = S_t - F_t e^{-\frac{TB(T-t)}{365}}
\] (B.1)
The dynamics between demand and convenience yield

where \( S \) denotes the spot price of the commodity, \( F \) the futures price, \( TB \) the treasury bill yield and \( T-t \) the time to maturity of the futures contract.

The net convenience yield can either take positive or negative values. Positive values imply that spot prices are higher than the futures, in which case the market is in backwardation and the level of inventory is, according to the cost-of-carry theory, low. In contrast, negative values of the net convenience yield should be the result of higher futures prices compared to spot prices, in which case the market is said to be in contango.

Summary statistics of the net convenience yield for Henry Hub and Central Appalachia coal prices are estimated for different monthly periods, which have been determined according to the volatility patterns illustrated in Figure 4. The periods considered are a) from January to February, b) from March to August that incorporates part of the refill season in gas wellheads and c) from September to December when price volatility is higher in the case of natural gas. For both commodities estimates of the convenience yield are reported in dollars per MMBtu in order comparison to be feasible.

The results indicate (Table 1) that during the January-February period, when the colder days of the year are normally recorded, the Henry hub net convenience yield is positive and higher than the Central Appalachia. For instance in 2009 and 2010 the net convenience yield in Henry hub futures contracts is almost 35 times higher than the CAPP futures contracts. In addition, during that period working gas in storage and coal stocks as well, reach their yearly lower levels. These estimates support the presumption that in commodity markets where consumption is driven by various economic sectors higher estimates of the convenience yield associate with increased spot prices.

Table 1: Mean estimates of the convenience yield for Henry Hub natural gas and Central Appalachia coal futures contracts

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<td></td>
</tr>
<tr>
<td></td>
<td>0.109</td>
<td>-0.055</td>
<td>NA</td>
<td>NA</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>0.330</td>
<td>-0.085</td>
<td>NA</td>
<td>NA</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>0.157</td>
<td>-0.022</td>
<td>NA</td>
<td>NA</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

(*1-pos refers to futures contracts with monthly duration and 3-pos to futures contracts with three months duration)

In contrast, estimates of the net convenience yield in the rest categories examined are quite different. In the case of Henry hub futures contracts negative estimates are observed,
The dynamics between demand and convenience yield

particularly from September until December. Thus, during the months leading to winter the natural gas futures market undergoes a contango since the futures price is higher than the spot price. At the same time an increase in the level of gas inventory takes place (as it has been illustrated in Figure 6B).

Those estimates for the Henry hub net convenience yield can be attributed to the magnitude of the spread between futures and spot prices. For instance, from September to December of 2010 the price of natural gas futures contracts for delivery in the next month was higher, on average, by $0.2 per MMBtu compared to the spot price and by $0.4 per MMbtu for contracts expiring in three months. Instead, at the beginning of 2010 (January to February) Henry hub spot price was higher by $0.17 per MMbtu for both contracts' maturities incorporated in our analysis (see again Figure 8).

**Figure 8: Henry hub spot-futures prices*, 2010**

A. January to February 2010

B. March to August 2010

C. September to December 2010

(*) Futures contracts for delivery in the next month

Higher futures prices during the last months of the year come along with an increase of long positions in the futures markets as traders anticipate that the Henry hub spot price will increase because of the higher demand for natural gas during the winter. Figure 9 shows that the number of long positions in the NYMEX futures market was higher, compared to the previous months, during the last months of 201058.

58 Data on Figure 9 refer to long positions in NYMEX by commercial traders who account for almost half of open interest. Commercial traders are those who use futures contracts for hedging purposes,
Assuming a trader who goes long in November it is expected that at the date that delivery of natural gas will take place, he will be better off if the spot price is above the futures’ price. This event is very likely to occur given that the Henry Hub spot price is normally higher during winter. Therefore, increased demand for futures contacts leads to higher futures prices as well.

**Figure 9: Long positions in Henry hub futures contracts by commercial traders**

![Graph showing long positions in Henry hub futures contracts by commercial traders.](image)


tt) See footnote 4 for the definition of Commercial traders

In the case of coal, smaller variations in the spot and futures prices compared to natural gas result in smaller estimates of the convenience yield as well. In addition small differences are recorded among the categories presumed, whereas the yearly average is positive which indicates that the market is in backwardation.

5. Correlation between convenience yield and spot prices

According to Pindyck (2001) convenience yield and spot prices should be positively correlated. The correlation does not only emerge from the interpretation of convenience yield as the spread between spot and futures prices but indicates also the relationship between the spot price and the long-run marginal cost of production assumed in competitive markets.

According to this view, higher spot prices should result from temporary shifts in demand or supply that in turn will lead the short-run marginal production cost at higher level compared to the long-run marginal cost. This situation will result to an increase in the demand for inventories because the latter have the ability to reallocate production across time reducing subsequently the costs of production.

according to the Commodity Futures Trading Commission. Commercial traders hold positions both in the underlying commodity and in the futures [http://www.cftc.gov/oce/web/natural_gas.htm](http://www.cftc.gov/oce/web/natural_gas.htm)

59 In contrast to Henry Hub natural gas there is a lack of in-depth data with respect to the coal market.

60 There are not available data for the volume of futures contracts traded in long and short positions as in the case of the Henry hub natural gas.
Table 2: Correlation coefficients between spot prices and convenience yield (futures contracts maturing the next month)

<table>
<thead>
<tr>
<th></th>
<th>Pearson Correlation</th>
<th>p-value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Natural gas</td>
<td>0.168</td>
<td>0.000</td>
</tr>
<tr>
<td>Coal</td>
<td>0.393</td>
<td>0.000</td>
</tr>
</tbody>
</table>

For that purpose, we estimate the correlation coefficients between spot price and convenience yields for Henry Hub natural gas and Central Appalachia coal markets. Table 2 shows that the two variables are positively correlated in both markets, with estimates being statistically significant according to the Pearson statistic. The higher estimate in the case of Appalachia coal is related to the lower standard deviation of the spot price and the convenience yield as well in the denominator.

Finally, we test the previous arguments with respect to the relationship between the convenience yield and the spot price by taking into consideration a regression analysis proposed by Chiou and Zhu (2006) who argue that Pindyck’s (2001) arguments with respect to the convenience yield can be summarized in the following relationship:

\[ CY_t = \alpha_0 + \alpha_1 \hat{P}_t + \alpha_2 \sigma_t^2 + \alpha_3 SD_t + \epsilon_t \]  (B.2)

where CY is the net convenience yield, \( \hat{P}_t \) is the spot price shock, which is modelled as the residuals from an ARMA(1,1) process of log spot prices, \( \sigma_t^2 \) is the proxy for the price volatility estimated as the residual from the ARMA(1,1) of the \( \sqrt{\frac{\pi}{2}} \times |\log P_t - \log P_{t-1}| \) series, and SD\( t \) represents the gas storage shock modelled as the residual from an ARMA(1,1) of the storage difference from the five-year average. The relationship implies that the \( \alpha_1 \) and \( \alpha_2 \) parameters should be positive, whereas \( \alpha_3 \) to be negative.

However, in our case B.2 is rearranged in part since we take into consideration the level of stocks, instead of the deviation from the long average mean level; hence it is rewritten as:

\[ CY_t = \alpha_0 + \alpha_1 \hat{P}_t + \alpha_2 \sigma_t^2 + \alpha_3 \log(\text{Inventory})_t + \epsilon_t \]  (B.3)

---

61 The statistical significance of Pearson’s correlation coefficient is tested using a t-test. The hypotheses for this test are:

\( H_0 : \rho = 0 \)
\( H_1 : \rho \neq 0 \)

A low p-value for this test (less than 0.05 for example) means that there is evidence to reject the null hypothesis in favour of the alternative hypothesis, or that there is a statistically significant relationship between the two variables.

62 This is mainly done because in the form of B.2 the results that we obtain are inconclusive. Instead there is a better fit of the regression coefficients by using the specific variable which is also directly associated with the implications of the storage.
According to the implications of the storage theory $a_1$ and $a_2$ should be positive and $a_3$ to be negative.

Table 3: Estimated regression coefficients of the convenience yield determinants

<table>
<thead>
<tr>
<th></th>
<th>Natural Gas</th>
<th></th>
<th>Coal</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>1-pos</td>
<td>12-pos</td>
<td>1-pos</td>
<td>12-pos</td>
</tr>
<tr>
<td>$a_0$</td>
<td>8.799</td>
<td>23.178</td>
<td>-12.552</td>
<td>17.810</td>
</tr>
<tr>
<td></td>
<td>(0.000)</td>
<td>(0.000)</td>
<td>(0.523)</td>
<td>(0.0197)</td>
</tr>
<tr>
<td>$a_1$</td>
<td>2.187</td>
<td>9.743</td>
<td>-14.084</td>
<td>27.226</td>
</tr>
<tr>
<td></td>
<td>(0.009)</td>
<td>(0.000)</td>
<td>(0.0283)</td>
<td>(0.0081)</td>
</tr>
<tr>
<td>$a_2$</td>
<td>0.104</td>
<td>0.223</td>
<td>0.034</td>
<td>-0.167</td>
</tr>
<tr>
<td></td>
<td>(0.020)</td>
<td>(0.028)</td>
<td>(0.2960)</td>
<td>(0.0005)</td>
</tr>
<tr>
<td>$a_3$</td>
<td>-1.421</td>
<td>-3.757</td>
<td>1.045</td>
<td>-22.891</td>
</tr>
<tr>
<td></td>
<td>(0.000)</td>
<td>(0.000)</td>
<td>(0.526)</td>
<td>(0.000)</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th></th>
<th>Adj-R$^2$</th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>31%</td>
<td>51%</td>
<td>9%</td>
<td>67%</td>
</tr>
<tr>
<td>DW</td>
<td>0.55</td>
<td>0.47</td>
<td>1.45</td>
<td>2.05</td>
</tr>
</tbody>
</table>

Inventory levels for natural gas and coal respectively are reported on a monthly basis, by the Energy Information Administration, and due to that reason monthly average estimates of the convenience yields (the dependent variable) are also considered. According to the results illustrated on Table 3, the inverse relationship between convenience yield and inventory is more clearly depicted in the case of coal for contracts maturing twelve months ahead. In particular, a decrease (increase) in stocks by 1% in the coal market leads to about $0.22 per short ton increase (decrease) in the convenience yield, whereas in the case of Henry hub natural gas the respective change is equal to 0.04 cents per MMBtu.

On the other hand, shocks in the spot price, as these are determined by the $\bar{P}_t$ variable, have an impact on Henry hub convenience yield given that for both maturities examined the coefficient is statistically significant. In addition, the effect is higher in the case of 12-pos contracts –almost four times higher relatively to the contracts maturing the next month. In the case of the Central Appalachia, however, the results are contradictory since for one month ahead the spot price shock is negatively related to the convenience yield, in contrast to the distant maturity where the shock has a positive impact, which is also higher from the Henry hub convenience yield. Given that a shift in the spot price (or a price shock) leads to higher estimates of the convenience yield the preceding result might be related to the lower degree of variation the prices of long term agreements exhibit in the coal market.

Finally, the relationship conveying the convenience yield and the price volatility is evident in the case of natural gas prices, a finding which is supported by the significant fluctuation that the prices exhibit, as it has been shown in Figure 4. In contrast, small variations in Central Appalachia coal prices may be the explanation of the insignificant impact for the 1-pos case and the negative impact in the case of futures contracts maturing after 12 months.

$^{63}$ However, the specific relationship does not provide significant information given that the rest of the regression coefficients are not statistically significant, whereas the value of the R$^2$ is low.
6. Conclusions

The uses of natural gas in the US exceed those of coal since it meets households’ energy demand and industrial operations. In contrast, coal is mostly used by the power industry for base-load electricity generation. Those features impose different characteristics on demand and supply for each of the energy resources, which are mainly reflected in the market prices. Therefore, fluctuation in natural gas spot prices is higher than in coal prices, whereas in the former case a seasonal pattern is more evident following the increased demand for gas mainly during the winter season.

By examining the demand dynamics that these energy resources exhibit with respect to the convenience yield we arrive at some useful conclusions. The convenience yield in the Henry hub futures contracts is higher compared to that of Central Appalachia during the periods of increased demand (that is winter). This observation associates with the fact that during that period an increase in the spot price over the futures prices (i.e., the market is in backwardation) is often recorded as a result of tightness in the supply side in order to correspond to the higher gas consumption. At that period also the amount of gas in storage diminishes, justifying higher values of the convenience yield according to the implications of the storage theory. In contrast, demand peaks in the coal market have a lower impact on the spot price given that coal demand is almost entirely driven by the power industry; hence the impact from unexpected shifts in demand should be lower compared to natural gas.

By considering the work of Chiou and Zhu (2006) who employ the residuals from an ARMA(1,1) process of log spot prices as an approximation of possible shocks in the spot price we observe that this variable has a positive impact on the convenience yield of Henry hub futures contracts. With respect to the inverse relationship between convenience yield and inventory, suggested by the cost-of-carry, the regression estimates confirm the presumption for both energy resources.

In conclusion, the market condition of the commodity’s market, either backwardation or contango, is a main determinant of the convenience yield. In commodity markets where consumption can be substituted by other commodities it is expected that price shocks are less usual and respectively the level of the spot price should not substantially diverge from that of the futures prices adjusted by the interest rate. On the other hand, in the absence of substitute goods it should be expected that commodity markets will exhibit backwardation (spot prices higher than futures prices), mainly during the periods of higher consumption, and subsequently the convenience yield will be higher as well.

Bibliography – Appendix B
The dynamics between demand and convenience yield


Appendix C

In the following section we examine the relationship between the measure of the convenience yield used in this study and the level of inventory.
The relationship between convenience yield and inventory

A direct test between convenience yield and inventory

According to the theory of storage, the convenience yield is inversely related to the level of inventory implying that the marginal net benefits of holding stocks decline with increased inventory. This is mainly attributed to the increased cost of holding inventories as storage space diminishes. In case of rising storage costs, users of a commodity have increased preferences for commodities available in the future instead of having the commodity available now. As Brennan notes by the time the convenience yield is a decreasing function of stocks, the convenience yield may exceed the expenditure on physical storage when stocks are relatively small and subsequently the futures price will be below the spot price. In addition, the theory presumes that the rate of decline in convenience yield diminishes with inventory i.e.,

\[
\text{Convenience yield}_t = f(\text{Total Stocks})_t
\]  

(C.1)

with \( f' > 0 \) and \( f'' < 0 \) (where \( f' \) and \( f'' \) are the first and second derivatives).

In the proposed relationship of the study we argue that the convenience yield and its inverse relationship with inventory is the most appropriate proxy in order to examine the indirect storage in the power industry. Thereupon, in order to be consistent with this view we examine if the inverse relationship (implied by the storage theory) is supported by the historical data undertaken.

For that purpose, a direct test between the two variables is taken into consideration which takes the form:

\[
\text{cy}_t = a_0 + \beta_0 \ln(\text{Stock level})_t + \epsilon_t
\]  

(C.2)

In the literature it is suggested that a semi-logarithmic specification should be used in order to account for the nonlinearity in convenience yield-inventory relation since the second derivative of the yield with respect to inventory level is positive (Cho and McDougall, page 615[11C]). According to the theory the coefficient \( \beta_0 \) of the stock level variable should be negative and statistically significant.

2a. The case of Natural gas

Firstly, we examine if the inverse relationship between convenience yield and inventory holds in the case of natural gas. We use data for working gas in storage which is the amount of gas in underground facilities available for withdrawal. Monthly observations have been obtained from the Energy Information Administration (EIA) website.

As a first step we test for the existence of unit roots in the data. In case of non-stationarity the regression should be taken in first differences in order to avoid spurious results.
The relationship between convenience yield and inventory

By applying the Augmented Dickey-Fuller test we conclude that the series is integrated of order one. By the time the convenience yield is stationary (as it has been seen in chapter 4 of the study) it is implied that a cointegration relationship does not exist among the two variables.

Table 1: Dickey-Fuller test for working gas in storage (seasonally adjusted)

<table>
<thead>
<tr>
<th></th>
<th>Level</th>
<th>1st difference</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>t-statistic</td>
<td>Integration</td>
</tr>
<tr>
<td>Constant</td>
<td>-3.514</td>
<td>-1.825</td>
</tr>
<tr>
<td></td>
<td>-2.898</td>
<td></td>
</tr>
<tr>
<td></td>
<td>-2.587</td>
<td></td>
</tr>
<tr>
<td>Trend &amp; Intercept</td>
<td>-4.077</td>
<td>-2.228</td>
</tr>
<tr>
<td></td>
<td>-3.467</td>
<td></td>
</tr>
<tr>
<td></td>
<td>-3.160</td>
<td></td>
</tr>
<tr>
<td>None</td>
<td>-2.594</td>
<td>0.903</td>
</tr>
<tr>
<td></td>
<td>-1.945</td>
<td></td>
</tr>
<tr>
<td></td>
<td>-1.614</td>
<td></td>
</tr>
</tbody>
</table>

Subsequently, in order to avoid spurious results from the regression of a stationary dependent variable on a non-stationary regressor we employ the first differences and subsequently the estimated regression is of the form:

$$\Delta cy_t = \alpha_1 + \beta_1 \Delta \ln(\text{Stock level})_t + \varepsilon_t$$  \hspace{1cm} (C.3)

Likewise in the case of equation (2) the inverse relationship between the convenience yield and inventory should be associated with a negative and statistically significant coefficient of $\beta_1$.

Table 2 illustrates the results of the regression for one, three, six and twelve months to maturity of Henry Hub natural gas futures contracts. The proposed inverse relationship can be supported by the data obtained, since the estimated coefficient $\beta_1$ is negative and statistically significant for a level of significance lower than 10%.

Table 2: Regression results of convenience yield and inventory w.r.t Henry Hub natural gas spot and futures prices

<table>
<thead>
<tr>
<th></th>
<th>1-pos</th>
<th>3-pos</th>
<th>6-pos</th>
<th>12-pos</th>
</tr>
</thead>
<tbody>
<tr>
<td>$\alpha_1$</td>
<td>0.001</td>
<td>-0.011</td>
<td>-0.016</td>
<td>-0.004</td>
</tr>
<tr>
<td></td>
<td>(0.990)</td>
<td>(0.922)</td>
<td>(0.898)</td>
<td>(0.977)</td>
</tr>
<tr>
<td>$\beta_1$</td>
<td>-0.726</td>
<td>-4.099</td>
<td>-4.316</td>
<td>-7.184</td>
</tr>
<tr>
<td></td>
<td>(0.082)</td>
<td>(0.042)</td>
<td>(0.053)</td>
<td>(0.004)</td>
</tr>
<tr>
<td>$R^2$</td>
<td>4%</td>
<td>5%</td>
<td>5%</td>
<td>10%</td>
</tr>
<tr>
<td>DW</td>
<td>2.48</td>
<td>2.23</td>
<td>2.14</td>
<td>2.35</td>
</tr>
</tbody>
</table>

Similarly, the inverse relationship proposed by the theory of storage is examined for the case of Central Appalachia spot and futures prices. We follow the same pattern as in the case of working gas in storage. After adjusting the data for the seasonal pattern that they exhibit (which is however substantially smaller relatively to gas inventory) we examine the level of integration in the specific time series.
The relationship between convenience yield and inventory

Table 3 indicates that the series is integrated of order 1 implying that the first differences should by all means lead to stationarity. As in the case of natural gas the regression given by the relationship (C.3) is taken into consideration. Excluding the case of futures contracts for delivery during the next month, the coefficient estimates for the rest of the maturities examined (3 months, 6 months and 12 months) are negative and statistically significant for a level of significance lower than 10% (Table 4).

<table>
<thead>
<tr>
<th>Table 3: Dickey-Fuller test for coal inventory</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Level</strong></td>
</tr>
<tr>
<td></td>
</tr>
<tr>
<td>Constant</td>
</tr>
<tr>
<td>Trend &amp; Intercept</td>
</tr>
<tr>
<td>None</td>
</tr>
</tbody>
</table>

The result for the next month delivery of coal (negative estimate but statistically insignificant) may be related to the lack of data for the spot price and the use of the closest maturity as a proxy for the specific time series$^{64}$. This finding can be also associated with the fact that for the same maturity the coefficient of the marginal convenience yield does not offer an economic meaning to the basis of Mid-Columbia (Table 6.4).

<table>
<thead>
<tr>
<th>Table 4: Regression results of convenience yield and inventory w.r.t Central Appalachia spot and futures prices</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>1-pos</strong></td>
</tr>
<tr>
<td>$\alpha_1$</td>
</tr>
<tr>
<td>$\beta_1$</td>
</tr>
<tr>
<td>$R^2$</td>
</tr>
<tr>
<td>DW</td>
</tr>
</tbody>
</table>

In addition, the higher estimated $\beta_1$ coefficient for the 12-pos case (5th column of Table 4) compared to that of the 6-pos for instance, should be associated with the higher estimates of the net convenience yield given that the independent variable (the logarithm of stocks) remains the same in each of the cases examined (according to Table 4.10 the mean convenience yield for the 6-pos case is 1.13 whereas for the 12-pos is 1.01). According to the preceding it can be argued that the assumption of the convenience yield as a proxy of the level of inventory due to the inverse relationship among them is validated by the data employed in the study.

64 This assumption is underlined in chapter 4 of the study (page 80)
Bibliography – Appendix C